

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(X)
3. **Purpose:** NERC Standards CIP-002-3(X) through CIP-009-3(X) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. Applicability:

4.1. Within the text of Standard CIP-002-3(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of

the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4. Data Retention

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2** The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

- 1.5.1** None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change “Control Center” to “control center”	Errata
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	December 16, 2009	Approved by the NERC Board of Trustees	Update
3(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3(X)
3. **Purpose:** NERC Standards CIP-002-3(X) through CIP-009-3(X) provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. Applicability:

4.1. Within the text of Standard CIP-002-3(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.
- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of

the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

- M1. The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2. The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3. The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4. The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- 1.1.1 Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2 ERO for Regional Entity.
- 1.1.3 Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4. Data Retention

- 1.4.1 The Responsible Entity shall keep documentation required by Standard CIP-002-3(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- 1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

- 1.5.1 None.

2. Violation Severity Levels (To be developed later.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change “Control Center” to “control center”	Errata
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	December 16, 2009	Approved by the NERC Board of Trustees	Update
<u>3(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — Critical Cyber Asset Identification
2. **Number:** CIP-002-3b(X)
3. **Purpose:** NERC Standards CIP-002-3b(X) through CIP-009-3 provide a cyber security framework for the identification and protection of Critical Cyber Assets to support reliable operation of the Bulk Electric System.

These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3b(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. Applicability:

4.1. Within the text of Standard CIP-002-3b(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3b(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3b(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.

- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4. Data Retention

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3b(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	MEDIUM	N/A	N/A	N/A	The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.
R1.1.	LOWER	N/A	The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures.	The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria.	The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
R1.2.	MEDIUM	N/A	N/A	N/A	The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.
R1.2.1.	LOWER	N/A	N/A	N/A	N/A
R1.2.2.	LOWER	N/A	N/A	N/A	N/A
R1.2.3.	LOWER	N/A	N/A	N/A	N/A
R1.2.4.	LOWER	N/A	N/A	N/A	N/A
R1.2.5.	LOWER	N/A	N/A	N/A	N/A

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Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.2.6.	LOWER	N/A	N/A	N/A	N/A
R1.2.7.	LOWER	N/A	N/A	N/A	N/A
R2.	HIGH	N/A	N/A	The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.
R3.	HIGH	N/A	N/A	The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null.
R3.1.	LOWER	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
R3.2.	LOWER	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
R3.3.	LOWER	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
R4.	LOWER	N/A	The Responsible Entity does not have a signed and dated	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of

Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
			record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.)	approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.)	1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change “Control Center” to “control center”	Errata
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	December 16, 2009	Approved by the NERC Board of Trustees	Update
3a	May 9, 2012	Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees	
3b	February 7, 2013	Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees	
3b	March 21, 2013	FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)	
3b(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Appendix 1

Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

Requirement Number and Text of Requirement

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Identify specifically what requirement needs clarification (as submitted):

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

Question Summary

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

Response

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

A. Introduction

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These standards recognize the differing roles of each entity in the operation of the Bulk Electric System, the criticality and vulnerability of the assets needed to manage Bulk Electric System reliability, and the risks to which they are exposed.

Business and operational demands for managing and maintaining a reliable Bulk Electric System increasingly rely on Cyber Assets supporting critical reliability functions and processes to communicate with each other, across functions and organizations, for services and data. This results in increased risks to these Cyber Assets.

Standard CIP-002-3b(X) requires the identification and documentation of the Critical Cyber Assets associated with the Critical Assets that support the reliable operation of the Bulk Electric System. These Critical Assets are to be identified through the application of a risk-based assessment.

4. Applicability:

4.1. Within the text of Standard CIP-002-3b(X), “Responsible Entity” shall mean:

- 4.1.1 Reliability Coordinator.
- 4.1.2 Balancing Authority.
- 4.1.3 Interchange Authority.
- 4.1.4 Transmission Service Provider.
- 4.1.5 Transmission Owner.
- 4.1.6 Transmission Operator.
- 4.1.7 Generator Owner.
- 4.1.8 Generator Operator.
- 4.1.9 Load Serving Entity.
- 4.1.10 NERC.
- 4.1.11 Regional Entity.

4.2. The following are exempt from Standard CIP-002-3b(X):

- 4.2.1 Facilities regulated by the U.S. Nuclear Regulatory Commission or the Canadian Nuclear Safety Commission.
- 4.2.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

5. **Effective Date:** The first day of the third calendar quarter after applicable regulatory approvals have been received (or the Reliability Standard otherwise becomes effective the first day of the third calendar quarter after BOT adoption in those jurisdictions where regulatory approval is not required)

B. Requirements

- R1.** Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.
- R1.1.** The Responsible Entity shall maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
- R1.2.** The risk-based assessment shall consider the following assets:
- R1.2.1.** Control centers and backup control centers performing the functions of the entities listed in the Applicability section of this standard.
- R1.2.2.** Transmission substations that support the reliable operation of the Bulk Electric System.
- R1.2.3.** Generation resources that support the reliable operation of the Bulk Electric System.
- R1.2.4.** Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration.
- R1.2.5.** Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.
- R1.2.6.** ~~Special Protection System~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- R1.2.7.** Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment.
- R2.** Critical Asset Identification — The Responsible Entity shall develop a list of its identified Critical Assets determined through an annual application of the risk-based assessment methodology required in R1. The Responsible Entity shall review this list at least annually, and update it as necessary.
- R3.** Critical Cyber Asset Identification — Using the list of Critical Assets developed pursuant to Requirement R2, the Responsible Entity shall develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset. Examples at control centers and backup control centers include systems and facilities at master and remote sites that provide monitoring and control, automatic generation control, real-time power system modeling, and real-time inter-utility data exchange. The Responsible Entity shall review this list at least annually, and update it as necessary. For the purpose of Standard CIP-002-3b(X), Critical Cyber Assets are further qualified to be those having at least one of the following characteristics:
- R3.1.** The Cyber Asset uses a routable protocol to communicate outside the Electronic Security Perimeter; or,
- R3.2.** The Cyber Asset uses a routable protocol within a control center; or,
- R3.3.** The Cyber Asset is dial-up accessible.

- R4.** Annual Approval — The senior manager or delegate(s) shall approve annually the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets. Based on Requirements R1, R2, and R3 the Responsible Entity may determine that it has no Critical Assets or Critical Cyber Assets. The Responsible Entity shall keep a signed and dated record of the senior manager or delegate(s)'s approval of the risk-based assessment methodology, the list of Critical Assets and the list of Critical Cyber Assets (even if such lists are null.)

C. Measures

- M1.** The Responsible Entity shall make available its current risk-based assessment methodology documentation as specified in Requirement R1.
- M2.** The Responsible Entity shall make available its list of Critical Assets as specified in Requirement R2.
- M3.** The Responsible Entity shall make available its list of Critical Cyber Assets as specified in Requirement R3.
- M4.** The Responsible Entity shall make available its approval records of annual approvals as specified in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- 1.1.1** Regional Entity for Responsible Entities that do not perform delegated tasks for their Regional Entity.
- 1.1.2** ERO for Regional Entity.
- 1.1.3** Third-party monitor without vested interest in the outcome for NERC.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints

1.4. Data Retention

- 1.4.1** The Responsible Entity shall keep documentation required by Standard CIP-002-3b(X) from the previous full calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

1.4.2 The Compliance Enforcement Authority in conjunction with the Registered Entity shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

1.5.1 None.

2. Violation Severity Levels

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	MEDIUM	N/A	N/A	N/A	The responsible entity has not documented a risk-based assessment methodology to use to identify its Critical Assets as specified in R1.
R1.1.	LOWER	N/A	The Responsible Entity maintained documentation describing its risk-based assessment methodology which includes evaluation criteria, but does not include procedures.	The Responsible Entity maintained documentation describing its risk-based assessment methodology that includes procedures but does not include evaluation criteria.	The Responsible Entity did not maintain documentation describing its risk-based assessment methodology that includes procedures and evaluation criteria.
R1.2.	MEDIUM	N/A	N/A	N/A	The Responsible Entity did not consider all of the asset types listed in R1.2.1 through R1.2.7 in its risk-based assessment.
R1.2.1.	LOWER	N/A	N/A	N/A	N/A
R1.2.2.	LOWER	N/A	N/A	N/A	N/A
R1.2.3.	LOWER	N/A	N/A	N/A	N/A
R1.2.4.	LOWER	N/A	N/A	N/A	N/A
R1.2.5.	LOWER	N/A	N/A	N/A	N/A

Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.2.6.	LOWER	N/A	N/A	N/A	N/A
R1.2.7.	LOWER	N/A	N/A	N/A	N/A
R2.	HIGH	N/A	N/A	The Responsible Entity has developed a list of Critical Assets but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of its identified Critical Assets even if such list is null.
R3.	HIGH	N/A	N/A	The Responsible Entity has developed a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 but the list has not been reviewed and updated annually as required.	The Responsible Entity did not develop a list of associated Critical Cyber Assets essential to the operation of the Critical Asset list as per requirement R2 even if such list is null.
R3.1.	LOWER	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
R3.2.	LOWER	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
R3.3.	LOWER	N/A	N/A	N/A	A Cyber Asset essential to the operation of the Critical Asset was identified that met the criteria in this requirement but was not included in the Critical Cyber Asset List.
R4.	LOWER	N/A	The Responsible Entity does not have a signed and dated	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s)'s annual	The Responsible Entity does not have a signed and dated record of the senior manager or delegate(s) annual approval of

Standard CIP-002-3b(X) — Cyber Security — Critical Cyber Asset Identification

Requirement	VRF	Lower VSL	Moderate VSL	High VSL	Severe VSL
			record of the senior manager or delegate(s)'s annual approval of the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.)	approval of two of the following: the risk-based assessment methodology, the list of Critical Assets or the list of Critical Cyber Assets (even if such lists are null.)	1) A risk based assessment methodology for identification of Critical Assets, 2) a signed and dated approval of the list of Critical Assets, nor 3) a signed and dated approval of the list of Critical Cyber Assets (even if such lists are null.)

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 16, 2006	R3.2 — Change “Control Center” to “control center”	Errata
2		Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3	
3	December 16, 2009	Approved by the NERC Board of Trustees	Update
3a	May 9, 2012	Interpretation of R3 for Duke Energy adopted by the NERC Board of Trustees	
3b	February 7, 2013	Interpretation of R1.2.5 for OGE adopted by the NERC Board of Trustees	
3b	March 21, 2013	FERC Order issued remanding interpretation of R3 for Duke Energy; interpretation removed from standard (previously Appendix 1)	
3b 3b(X)	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Appendix 1

Project 2012-INT-05: Response to Request for an Interpretation of NERC Standard CIP-002-3 for the OGE Energy Corporation

Date submitted: 2/24/11

The following interpretation of NERC Standard CIP-002-3 Cyber Security — Critical Cyber Asset Identification, Requirement R1.2.5, was developed by a project team from the CIP Interpretation Drafting Team.

Requirement Number and Text of Requirement

R1. Critical Asset Identification Method — The Responsible Entity shall identify and document a risk-based assessment methodology to use to identify its Critical Assets.

R1.2. The risk-based assessment shall consider the following assets:

R1.2.5. Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Identify specifically what requirement needs clarification (as submitted):

Requirement Number and Text of Requirement:

CIP-002-3 R1.2.5 - Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more.

Clarification needed: Based on the text above, an auditor could apply this standard to the Smart Grid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality. While the AMI system is not designed to perform automatic load shedding of 300 MW it could be repurposed to shed an aggregate load of 300 MW or more. However, it is important to note that the AMI remote disconnect function is not used for under-voltage load shedding or under-frequency load shedding as a part of the region's load shedding program.

The primary purpose of the AMI remote connect/disconnect function is to connect and disconnect individual retail electric customers from a central location rather than at the meter itself to enable substantial efficiency gains.

OGE would like NERC to clarify that a company's SmartGrid AMI functionality, which may be able to disconnect 300+ MW of load, is not considered a system or facility critical to automatic load shedding

under a common control system capable of shedding 300 mw and therefore it should not be included in the Company's risk based methodology. OGE believes this clarification is appropriate because CIP-002-3 R1.2.5 was written to address under-voltage and under-frequency load shedding systems; SmartGrid AMI disconnect functionality pertains to neither.

Question Summary

OGE Energy Corporation seeks clarification on the meaning of CIP-002-3, Requirement R1.2.5 as it relates to “SmartGrid Advanced Meter Infrastructure (AMI) remote connect/disconnect functionality.”

In its response, the Interpretation Drafting Team will answer whether a company’s SmartGrid AMI functionality, which may be able to disconnect more than 300 MW of load, is considered a system or facility critical to automatic load shedding under a common control system capable of shedding 300 MW or more under CIP-002-3, Requirement 1.2.5.

Response

In evaluating OGE’s request, the Interpretation Drafting Team (IDT) clarifies the meaning of CIP-002-3, Requirement R1.2.5 as it relates and applies to new technologies such as AMI. CIP-002-3, Requirement R1.2.5, along with the context of the standard as a whole, informed development of this interpretation.

CIP-002-3, Requirement R1.2 specifies that the Responsible Entity’s risk-based assessment methodology (“RBAM”) “shall consider” the assets described in Requirement R1.2.5.

During the identification and documentation of the RBAM, a Responsible Entity shall consider “Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more” as specified in Requirement R1.2.5. Requirement R2 then requires the entity to apply this RBAM annually to identify Critical Assets. If a system or facility does not meet the specifications of Requirement R1.2.5, the RBAM is not required to consider that asset.

The Critical Asset identification method under CIP-002-3, Requirement R1 is based on a facts and circumstance-driven analysis and is not dependent exclusively on specific technology or specific types of systems or facilities. For instance, systems or facilities such as AMI may have the potential or capability to be set up to automatically shed load, but having that potential or capability does not necessarily mean that the system or facility performs the function as described in Requirement R1.2.5. Therefore, an AMI system specifically built and configured to perform the Remote Disconnect function that does not automatically shed load without human operator initiation would not meet the criteria found in CIP-002-3, Requirement R1.2.5.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-5.1(X)
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3. **Generator Operator**
 - 4.1.4. **Generator Owner**
 - 4.1.5. **Interchange Coordinator or Interchange Authority**

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-5.1(X):

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

1. **24 Months Minimum** – CIP-002-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required CIP-002-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

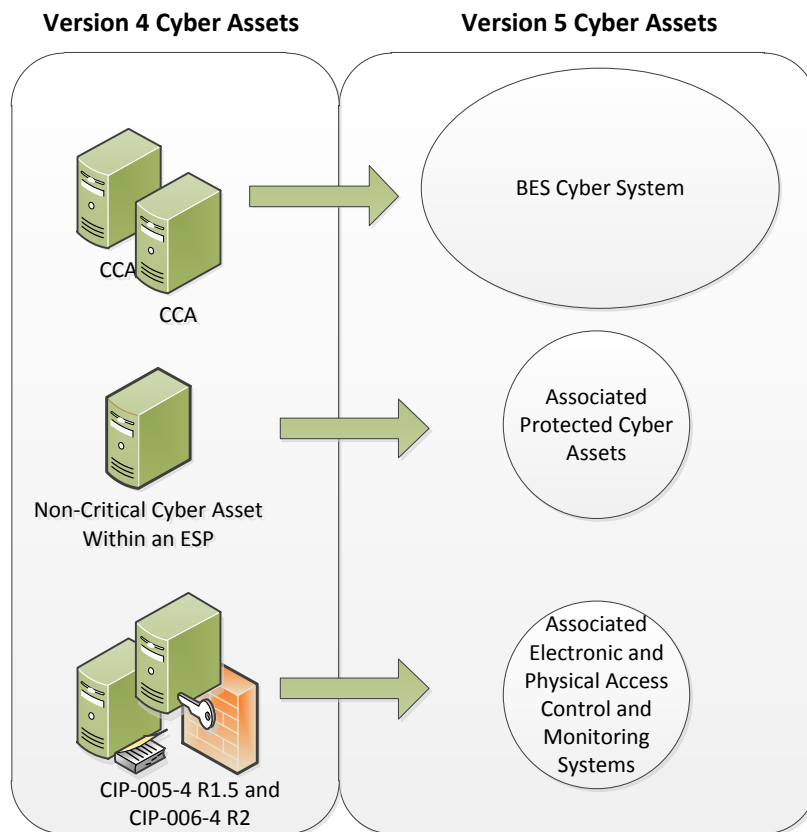
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and

scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

Electronic Access Control or Monitoring Systems (“EACMS”) – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

Physical Access Control Systems (“PACS”)– Examples include: authentication servers, card systems, and badge control systems.

Protected Cyber Assets (“PCA”) – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i.** Control Centers and backup Control Centers;
 - ii.** Transmission stations and substations;
 - iii.** Generation resources;
 - iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
 - 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
 - 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
- 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

CIP-002-5.1(X) - Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4.** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or 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.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each Remedial Action Scheme (RAS) or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.
- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1(X) and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1(X). This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-5.1(X)

CIP-002-5.1(X) requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber

Systems that would be subject to CIP-002-5.1(X). The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1(X), these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.
- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some

of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Remedial Action Schemes as medium impact. Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC’s document “[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)”, Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate

connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Remedial Action Schemes (RAS) or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaAR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.
- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

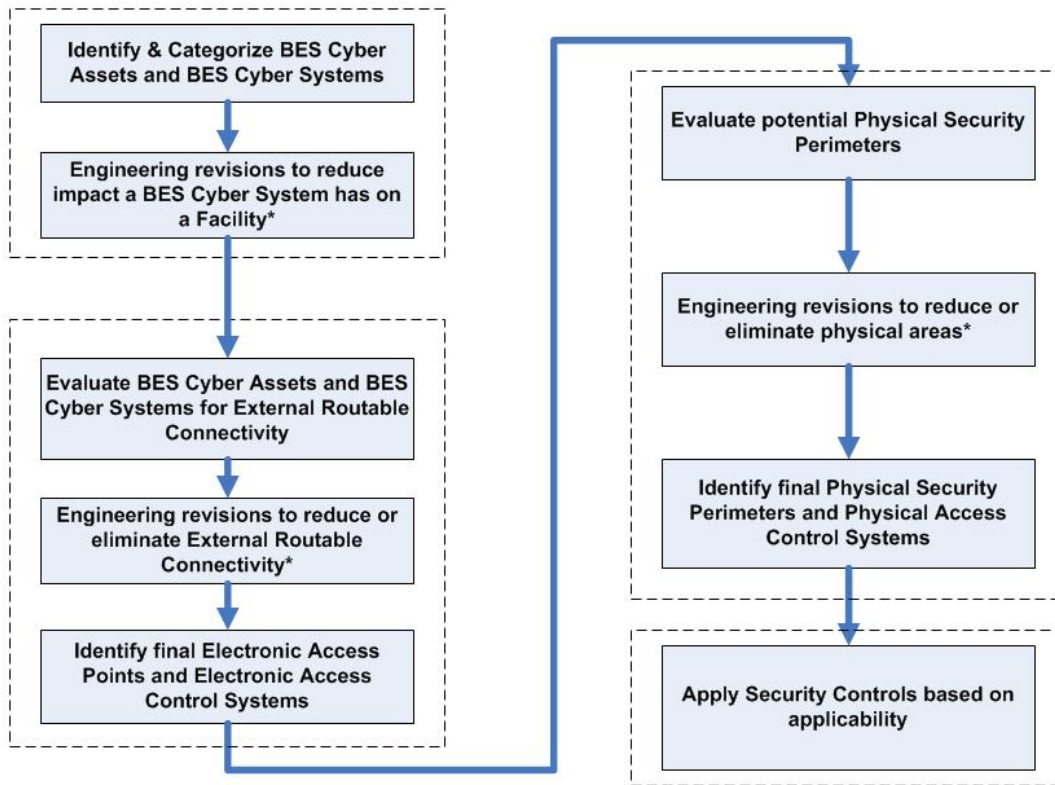
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3.	Update

Guidelines and Technical Basis

		Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1. (Order becomes effective on 2/3/14.)	
5.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-5.1(X)
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1. **Balancing Authority**
 - 4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
 - 4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3. **Generator Operator**
 - 4.1.4. **Generator Owner**

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-5.1(X):

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

1. **24 Months Minimum** – CIP-002-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required CIP-002-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

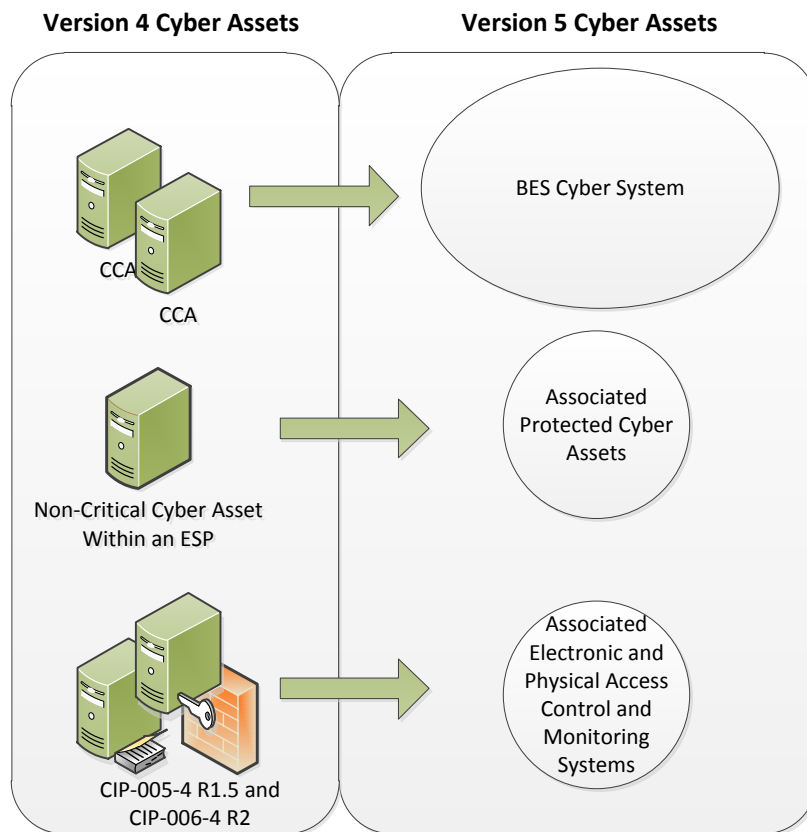
This standard provides “bright-line” criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team’s review of the NIST Risk Management Framework and the use of an analogous term “information system” as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and

scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

Electronic Access Control or Monitoring Systems (“EACMS”) – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

Physical Access Control Systems (“PACS”)– Examples include: authentication servers, card systems, and badge control systems.

Protected Cyber Assets (“PCA”) – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: [*Violation Risk Factor: High*][*Time Horizon: Operations Planning*]
- i.** Control Centers and backup Control Centers;
 - ii.** Transmission stations and substations;
 - iii.** Generation resources;
 - iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
 - v.** ~~Special Protection Systems~~ Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and
 - vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
- 1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;
 - 1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and
 - 1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).
- M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- 2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and
- 2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	High	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p>	<p>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>	<p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly</p>	<p>For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly</p>	<p>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</p>	<p>categorized at a lower category.</p> <p>OR</p> <p>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</p>	<p>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;</p> <p>OR</p> <p>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning	Lower	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</p>	<p>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)</p> <p>OR</p> <p>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</p>

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

CIP-002-5.1(X) - Attachment 1

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

- 1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
- 1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
- 1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
- 1.4.** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

- 2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
- 2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

- 2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
- 2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.
- 2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

- 2.6. Generation at a single plant location or 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.
- 2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.
- 2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.
- 2.9. Each ~~Special Protection System (SPS)~~, Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

- 2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.
- 2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.
- 2.12.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.
- 2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

- 3.1.** Control Centers and backup Control Centers.
- 3.2.** Transmission stations and substations.
- 3.3.** Generation resources.
- 3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
- 3.5.** ~~Special Protection Systems~~Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
- 3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1(X) and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1(X). This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-5.1(X)

CIP-002-5.1(X) requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber

Systems that would be subject to CIP-002-5.1(X). The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitoring & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
 - Providing actual reserve generation when called upon (GO,GOP)
 - Monitoring that reserves are sufficient (BA)
- Governor Response
 - Control system used to actuate governor response (GO)
- Protection Systems (transmission & generation)
 - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
 - Zone protection for breaker failure (DP, TO, TOP)
 - Breaker protection (DP, TO, TOP)
 - Current, frequency, speed, phase (TO,TOP, GO,GOP)
- ~~Special Protection Systems or~~ Remedial Action Schemes
 - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
- Under and Over Frequency relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Under and Over Voltage relay protection (includes automatic load shedding)
 - Sensors, relays & breakers (DP)
- Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
 - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
 - Software used to perform calculation (BA)
- Demand Response
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP,DP)
- Manually Initiated Load shedding
 - Ability to identify load change need (BA)
 - Ability to implement load changes (TOP, DP)

- Non-spinning reserve (contingency reserve)
 - Know generation status, capability, ramp rate, start time (GO, BA)
 - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
 - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
 - Software to calculate unit adjustments (BA)
 - Transmit adjustments to individual units (GOP)
 - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
 - Frequency source, schedule (BA)
 - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
 - Sensors, stator control system, feedback (GO)
- Capacitive resources
 - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
 - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
 - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
 - SCADA (TOP, GOP)
 - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
 - Through black start units (TOP, GOP)
 - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1(X), these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.
- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some

of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for ~~Special Protection Systems and~~ Remedial Action Schemes as medium impact. ~~Special Protection Systems and~~ Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases “Transmission Facilities at a single station or substation” and “Transmission stations or substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the “Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface.” This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
 - Excluded radial facilities that would only provide support for single generation facilities.
 - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC’s document “[Integrated Risk Assessment Approach – Refinement to Severity Risk Index](#)”, Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

In the terms of applicable lines and connecting “other Transmission stations or substations” determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate

connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.
2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those ~~Special Protection Systems (SPS)~~, Remedial Action Schemes (RAS); or automated switching Systems installed to ensure BES operation within IROs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROs if they fail to operate as designed. By the definition of IRO, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaAR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.
- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

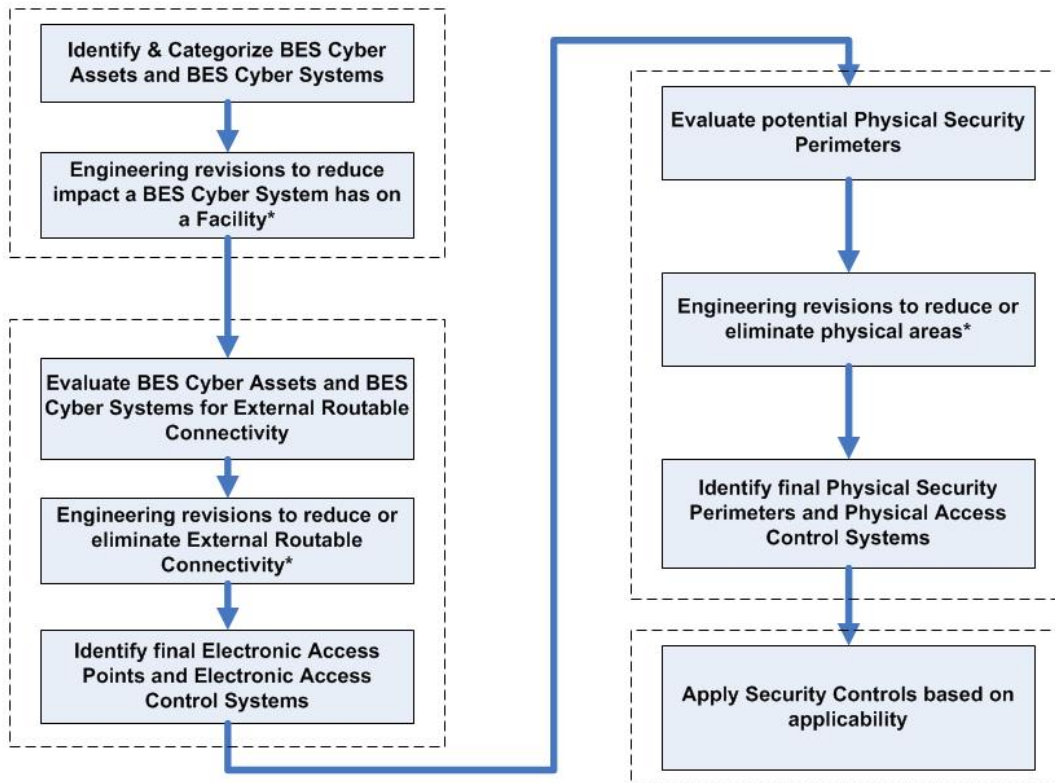
- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.

Overview (Generation Facility)



* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:

The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3.	Update

Guidelines and Technical Basis

		Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1. (Order becomes effective on 2/3/14.)	
<u>5.1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-5(X)
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-003-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

1. **24 Months Minimum** – CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval. CIP-003-5(X), Requirement R2 shall become effective on the later of July 1, 2016, or the first calendar day of the 13th calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, and CIP-003-5(X), Requirement R2 shall become effective on the first day of the 13th calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. **Background:**

Standard CIP-003-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5, CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies**, . . .

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements. The documented processes themselves are not required to include the ". . . identifies, assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented

processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

- R1.** Each Responsible Entity, for its high impact and medium impact BES Cyber Systems, shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 1.1** Personnel & training (CIP-004);
 - 1.2** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
 - 1.3** Physical security of BES Cyber Systems (CIP-006);
 - 1.4** System security management (CIP-007);
 - 1.5** Incident reporting and response planning (CIP-008);
 - 1.6** Recovery plans for BES Cyber Systems (CIP-009);
 - 1.7** Configuration change management and vulnerability assessments (CIP-010);
 - 1.8** Information protection (CIP-011); and
 - 1.9** Declaring and responding to CIP Exceptional Circumstances.
- M1.** Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
- R2.** Each Responsible Entity for its assets identified in CIP-002-5(X), Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Cyber security awareness;
 - 2.2** Physical security controls;
 - 2.3** Electronic access controls for external routable protocol connections and Dial-up Connectivity; and
 - 2.4** Incident response to a Cyber Security Incident.

An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required.

- M2.** Examples of evidence may include, but are not limited to, one or more documented cyber security policies and evidence of processes, procedures, or plans that demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

- R3.** Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium]*
[Time Horizon: Operations Planning]

- M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

- R4.** The Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower]* *[Time Horizon: Operations Planning]*

- M4.** An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did complete this review</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did complete this review</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1)</p> <p>OR</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>in less than or equal to 16 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of</p>	<p>in less than or equal to 17 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of</p>	<p>calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1)</p>	<p>The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 18 calendar</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1)	the previous approval. (R1)		months of the previous approval. (R1)
R2	Operations Planning	Lower	<p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 but did not identify,</p>	<p>The Responsible Entity did not document or implement any cyber security policies for assets with a low impact rating that address the topics as required by R2. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 18 calendar months of the previous review. (R2)</p> <p>OR</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p>	<p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p>	<p>assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to</p>	<p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 18 calendar months of the previous approval. (R2)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 15 calendar months but did not complete this approval in less than or equal to 16 calendar months of the previous approval. (R2)	approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 16 calendar months but did not complete this approval in less than or equal to 17 calendar months of the previous approval. (R2)	Requirement R2 within 17 calendar months but did not complete this approval in less than or equal to 18 calendar months of the previous approval. (R2)	
R3	Operations Planning	Medium	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			change in less than 40 calendar days of the change. (R3)	document this change in less than 50 calendar days of the change. (R3)	less than 60 calendar days of the change. (R3)	by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	Operations Planning	Lower	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a process to delegate actions from the CIP Senior Manager, and has Identified deficiencies but did not assess or correct the deficiencies.(R4) OR The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					process to delegate actions from the CIP Senior Manager, but did not identify, assess, or correct the deficiencies.(R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The number of policies and their specific language are guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The cyber security policy must cover in sufficient detail the nine topical areas required by CIP-003-5(X), Requirement R1. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R1. Implementation of the cyber security policy is not specifically included in CIP-003-5(X), Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-004 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements from CIP-004 through CIP-011, but rather to put together a holistic cyber security policy appropriate to its organization. The assessment through the Compliance Monitoring and Enforcement Program of policy items that extend beyond the scope of CIP-004 through CIP-011 should not be considered candidates for potential violations. The Responsible Entity should consider the following for each of the required topics in its cyber security policy:

1.1 Personnel & training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN “split-tunneling” or “dual-homed” workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity’s Interactive Remote Access controls

1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components

- Availability of system backups

1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

The Standard Drafting Team (SDT) has removed requirements relating to exceptions to a Responsible Entity's security policies since it is a general management issue that is not within the scope of a reliability requirement. The SDT considers it to be an internal policy requirement and not a reliability requirement. However, the SDT encourages Responsible Entities to continue this practice as a component of its cyber security policy.

In this and all subsequent required approvals in the NERC CIP Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

As with Requirement R1, the number of policies and their specific language would be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization or as components of specific programs. The cyber security policy must cover in sufficient detail the four topical areas required by CIP-003-5(X), Requirement R2. The Responsible Entity has flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R2. The intent of the requirement is to outline a set of basic protections that all low impact BES Cyber Systems should receive without requiring a significant administrative and compliance overhead. The SDT intends that demonstration of this requirement can be reasonably accomplished through providing evidence of related processes, procedures, or plans. While the audit staff may choose to review an example low impact BES Cyber System, the SDT believes strongly that the current method (as of this writing) of reviewing a statistical sample of systems

is not necessary. The SDT also notes that in topic 2.3, the SDT uses the term “electronic access control” in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing.

Requirement R3:

The intent of CIP-003-5(X), Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that this CIP Senior Manager play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-5(X), Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the Responsible Entity should have significant flexibility to adapt this requirement to their existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records provides a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up to date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

Annual review and approval of the cyber security policy ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for R2:

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

The language in Requirement R2, Part 2.3 “. . . for external routable protocol connections and Dial-up Connectivity . . .” was included to acknowledge the support given in FERC Order 761, paragraph 87, for electronic security perimeter protections “of some form” to be applied to all BES Cyber Systems, regardless of impact. Part 2.3 uses the phrase “external routable protocol connections” instead of the defined term “External Routable Connectivity,” because the latter term has very specific connotations relating to Electronic Security Perimeters and high and medium impact BES Cyber Systems. Using the glossary term “External Routable Connectivity” in the context of Requirement R2 would not be appropriate because Requirement R2 is limited in scope to low impact BES Cyber Systems.

Review and approval of the cyber security policy at least every 15 calendar months ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the *Glossary of Terms used in NERC Reliability Standards* so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the senior manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	Update to conform to changes to CIP-002-4 (Project 2008-06)
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5. (Order becomes effective 2/3/14.)	
5(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial

			Action Scheme and RAS
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A. Introduction

1. **Title:** Cyber Security — Security Management Controls
2. **Number:** CIP-003-5(X)
3. **Purpose:** To specify consistent and sustainable security management controls that establish responsibility and accountability to protect BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-003-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates:

1. **24 Months Minimum** – CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval. CIP-003-5(X), Requirement R2 shall become effective on the later of July 1, 2016, or the first calendar day of the 13th calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-003-5(X), except for CIP-003-5(X), Requirement R2, shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, and CIP-003-5(X), Requirement R2 shall become effective on the first day of the 13th calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-003-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5, CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying "implement" as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements. The documented processes themselves are not required to include the ". . . identifies, assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects

are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures provide examples of evidence to show documentation and implementation of the requirement. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

B. Requirements and Measures

- R1.** Each Responsible Entity, for its high impact and medium impact BES Cyber Systems, shall review and obtain CIP Senior Manager approval at least once every 15 calendar months for one or more documented cyber security policies that collectively address the following topics: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 1.1** Personnel & training (CIP-004);
 - 1.2** Electronic Security Perimeters (CIP-005) including Interactive Remote Access;
 - 1.3** Physical security of BES Cyber Systems (CIP-006);
 - 1.4** System security management (CIP-007);
 - 1.5** Incident reporting and response planning (CIP-008);
 - 1.6** Recovery plans for BES Cyber Systems (CIP-009);
 - 1.7** Configuration change management and vulnerability assessments (CIP-010);
 - 1.8** Information protection (CIP-011); and
 - 1.9** Declaring and responding to CIP Exceptional Circumstances.
- M1.** Examples of evidence may include, but are not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.
- R2.** Each Responsible Entity for its assets identified in CIP-002-5(X), Requirement R1, Part R1.3, shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented cyber security policies that collectively address the following topics, and review and obtain CIP Senior Manager approval for those policies at least once every 15 calendar months: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- 2.1** Cyber security awareness;
 - 2.2** Physical security controls;
 - 2.3** Electronic access controls for external routable protocol connections and Dial-up Connectivity; and
 - 2.4** Incident response to a Cyber Security Incident.

An inventory, list, or discrete identification of low impact BES Cyber Systems or their BES Cyber Assets is not required.

- M2.** Examples of evidence may include, but are not limited to, one or more documented cyber security policies and evidence of processes, procedures, or plans that demonstrate the implementation of the required topics; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager for each cyber security policy.

- R3.** Each Responsible Entity shall identify a CIP Senior Manager by name and document any change within 30 calendar days of the change. *[Violation Risk Factor: Medium]*
[Time Horizon: Operations Planning]

- M3.** An example of evidence may include, but is not limited to, a dated and approved document from a high level official designating the name of the individual identified as the CIP Senior Manager.

- R4.** The Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a documented process to delegate authority, unless no delegations are used. Where allowed by the CIP Standards, the CIP Senior Manager may delegate authority for specific actions to a delegate or delegates. These delegations shall be documented, including the name or title of the delegate, the specific actions delegated, and the date of the delegation; approved by the CIP Senior Manager; and updated within 30 days of any change to the delegation. Delegation changes do not need to be reinstated with a change to the delegator. *[Violation Risk Factor: Lower]* *[Time Horizon: Operations Planning]*

- M4.** An example of evidence may include, but is not limited to, a dated document, approved by the CIP Senior Manager, listing individuals (by name or title) who are delegated the authority to approve or authorize specifically identified items.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address one of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 15 calendar months but did complete this review</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address two of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 16 calendar months but did complete this review</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address three of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 within 17 calendar months but did complete this review in less than or equal to 18</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for its high impact and medium impact BES Cyber Systems, but did not address four or more of the nine topics required by R1. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have any documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1. (R1)</p> <p>OR</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>in less than or equal to 16 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 15 calendar months but did complete this approval in less than or equal to 16 calendar months of</p>	<p>in less than or equal to 17 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 16 calendar months but did complete this approval in less than or equal to 17 calendar months of</p>	<p>calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 17 calendar months but did complete this approval in less than or equal to 18 calendar months of the previous approval. (R1)</p>	<p>The Responsible Entity did not complete its review of the one or more documented cyber security policies as required by R1 within 18 calendar months of the previous review. (R1)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for its high impact and medium impact BES Cyber Systems as required by R1 by the CIP Senior Manager or delegate according to Requirement R1 within 18 calendar</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			the previous approval. (R1)	the previous approval. (R1)		months of the previous approval. (R1)
R2	Operations Planning	Lower	<p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only three of</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only two of</p>	<p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 and has identified deficiencies but did not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity documented and implemented one or more cyber security policies for assets with a low impact rating that address only one of the topics as required by R2 but did not identify,</p>	<p>The Responsible Entity did not document or implement any cyber security policies for assets with a low impact rating that address the topics as required by R2. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 18 calendar months of the previous review. (R2)</p> <p>OR</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 15 calendar months but did complete this review in less than or equal to 16 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p>	<p>the topics as required by R2 but did not identify, assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 16 calendar months but did complete this review in less than or equal to 17 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its</p>	<p>assess, or correct the deficiencies.</p> <p>OR</p> <p>The Responsible Entity did not complete its review of the one or more documented cyber security policies for assets with a low impact rating as required by R2 within 17 calendar months but did complete this review in less than or equal to 18 calendar months of the previous review. (R2)</p> <p>OR</p> <p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to</p>	<p>The Responsible Entity did not complete its approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 18 calendar months of the previous approval. (R2)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 15 calendar months but did not complete this approval in less than or equal to 16 calendar months of the previous approval. (R2)	approval of the one or more documented cyber security policies for assets with a low impact rating as required by R2 by the CIP Senior Manager according to Requirement R2 within 16 calendar months but did not complete this approval in less than or equal to 17 calendar months of the previous approval. (R2)	Requirement R2 within 17 calendar months but did not complete this approval in less than or equal to 18 calendar months of the previous approval. (R2)	
R3	Operations Planning	Medium	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 30 calendar days but did document this	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 40 calendar days but did	The Responsible Entity has identified by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 50 calendar days but did document this change in	The Responsible Entity has not identified, by name, a CIP Senior Manager. OR The Responsible Entity has identified

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			change in less than 40 calendar days of the change. (R3)	document this change in less than 50 calendar days of the change. (R3)	less than 60 calendar days of the change. (R3)	by name a CIP Senior Manager, but did not document changes to the CIP Senior Manager within 60 calendar days of the change. (R3)
R4	Operations Planning	Lower	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 30 calendar days but did document this change in less than 40 calendar days of the change. (R4)	The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 40 calendar days but did document this change in less than 50 calendar days of the change. (R4)	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a process to delegate actions from the CIP Senior Manager, and has Identified deficiencies but did not assess or correct the deficiencies.(R4) OR The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, has a	The Responsible Entity has used delegated authority for actions where allowed by the CIP Standards, but does not have a process to delegate actions from the CIP Senior Manager. (R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-003-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					process to delegate actions from the CIP Senior Manager, but did not identify, assess, or correct the deficiencies.(R4) OR The Responsible Entity has identified a delegate by name, title, date of delegation, and specific actions delegated, but did not document changes to the delegate within 50 calendar days but did document this change in less than 60 calendar days of the change. (R4)	not document changes to the delegate within 60 calendar days of the change. (R4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The number of policies and their specific language are guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization, or as components of specific programs. The cyber security policy must cover in sufficient detail the nine topical areas required by CIP-003-5(X), Requirement R1. The Responsible Entity has the flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R1. Implementation of the cyber security policy is not specifically included in CIP-003-5(X), Requirement R1 as it is envisioned that the implementation of this policy is evidenced through successful implementation of CIP-004 through CIP-011. However, Responsible Entities are encouraged not to limit the scope of their cyber security policies to only those requirements from CIP-004 through CIP-011, but rather to put together a holistic cyber security policy appropriate to its organization. The assessment through the Compliance Monitoring and Enforcement Program of policy items that extend beyond the scope of CIP-004 through CIP-011 should not be considered candidates for potential violations. The Responsible Entity should consider the following for each of the required topics in its cyber security policy:

1.1 Personnel & training (CIP-004)

- Organization position on acceptable background investigations
- Identification of possible disciplinary action for violating this policy
- Account management

1.2 Electronic Security Perimeters (CIP-005) including Interactive Remote Access

- Organization stance on use of wireless networks
- Identification of acceptable authentication methods
- Identification of trusted and untrusted resources
- Monitoring and logging of ingress and egress at Electronic Access Points
- Maintaining up-to-date anti-malware software before initiating Interactive Remote Access
- Maintaining up-to-date patch levels for operating systems and applications used to initiate Interactive Remote Access
- Disabling VPN “split-tunneling” or “dual-homed” workstations before initiating Interactive Remote Access
- For vendors, contractors, or consultants: include language in contracts that requires adherence to the Responsible Entity’s Interactive Remote Access controls

1.3 Physical security of BES Cyber Systems (CIP-006)

- Strategy for protecting Cyber Assets from unauthorized physical access
- Acceptable physical access control methods
- Monitoring and logging of physical ingress

1.4 System security management (CIP-007)

- Strategies for system hardening
- Acceptable methods of authentication and access control
- Password policies including length, complexity, enforcement, prevention of brute force attempts
- Monitoring and logging of BES Cyber Systems

1.5 Incident reporting and response planning (CIP-008)

- Recognition of Cyber Security Incidents
- Appropriate notifications upon discovery of an incident
- Obligations to report Cyber Security Incidents

1.6 Recovery plans for BES Cyber Systems (CIP-009)

- Availability of spare components

- Availability of system backups

1.7 Configuration change management and vulnerability assessments (CIP-010)

- Initiation of change requests
- Approval of changes
- Break-fix processes

1.8 Information protection (CIP-011)

- Information access control methods
- Notification of unauthorized information disclosure
- Information access on a need-to-know basis

1.9 Declaring and responding to CIP Exceptional Circumstances

- Processes to invoke special procedures in the event of a CIP Exceptional Circumstance
- Processes to allow for exceptions to policy that do not violate CIP requirements

The Standard Drafting Team (SDT) has removed requirements relating to exceptions to a Responsible Entity's security policies since it is a general management issue that is not within the scope of a reliability requirement. The SDT considers it to be an internal policy requirement and not a reliability requirement. However, the SDT encourages Responsible Entities to continue this practice as a component of its cyber security policy.

In this and all subsequent required approvals in the NERC CIP Standards, the Responsible Entity may elect to use hardcopy or electronic approvals to the extent that there is sufficient evidence to ensure the authenticity of the approving party.

Requirement R2:

As with Requirement R1, the number of policies and their specific language would be guided by a Responsible Entity's management structure and operating conditions. Policies might be included as part of a general information security program for the entire organization or as components of specific programs. The cyber security policy must cover in sufficient detail the four topical areas required by CIP-003-5(X), Requirement R2. The Responsible Entity has flexibility to develop a single comprehensive cyber security policy covering these topics, or it may choose to develop a single high-level umbrella policy and provide additional policy detail in lower level documents in its documentation hierarchy. In the case of a high-level umbrella policy, the Responsible Entity would be expected to provide the high-level policy as well as the additional documentation in order to demonstrate compliance with CIP-003-5(X), Requirement R2. The intent of the requirement is to outline a set of basic protections that all low impact BES Cyber Systems should receive without requiring a significant administrative and compliance overhead. The SDT intends that demonstration of this requirement can be reasonably accomplished through providing evidence of related processes, procedures, or plans. While the audit staff may choose to review an example low impact BES Cyber System, the SDT believes strongly that the current method (as of this writing) of reviewing a statistical sample of systems

is not necessary. The SDT also notes that in topic 2.3, the SDT uses the term “electronic access control” in the general sense, i.e., to control access, and not in the specific technical sense requiring authentication, authorization, and auditing.

Requirement R3:

The intent of CIP-003-5(X), Requirement R3 is effectively unchanged since prior versions of the standard. The specific description of the CIP Senior Manager has now been included as a defined term rather than clarified in the Standard itself to prevent any unnecessary cross-reference to this standard. It is expected that this CIP Senior Manager play a key role in ensuring proper strategic planning, executive/board-level awareness, and overall program governance.

Requirement R4:

As indicated in the rationale for CIP-003-5(X), Requirement R4, this requirement is intended to demonstrate a clear line of authority and ownership for security matters. The intent of the SDT was not to impose any particular organizational structure, but, rather, the Responsible Entity should have significant flexibility to adapt this requirement to their existing organizational structure. A Responsible Entity may satisfy this requirement through a single delegation document or through multiple delegation documents. The Responsible Entity can make use of the delegation of the delegation authority itself to increase the flexibility in how this applies to its organization. In such a case, delegations may exist in numerous documentation records as long as the collection of these documentation records provides a clear line of authority back to the CIP Senior Manager. In addition, the CIP Senior Manager could also choose not to delegate any authority and meet this requirement without such delegation documentation.

The Responsible Entity must keep its documentation of the CIP Senior Manager and any delegations up to date. This is to ensure that individuals do not assume any undocumented authority. However, delegations do not have to be re-instated if the individual who delegated the task changes roles or is replaced. For instance, assume that John Doe is named the CIP Senior Manager and he delegates a specific task to the Substation Maintenance Manager. If John Doe is replaced as the CIP Senior Manager, the CIP Senior Manager documentation must be updated within the specified timeframe, but the existing delegation to the Substation Maintenance Manager remains in effect as approved by the previous CIP Senior Manager, John Doe.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

Annual review and approval of the cyber security policy ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for R2:

One or more security policies enable effective implementation of the standard's requirements. The purpose of policies is to provide a management and governance foundation for all requirements that apply to personnel who have authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems. The Responsible Entity can demonstrate through its policies that its management supports the accountability and responsibility necessary for effective implementation of the standard's requirements.

The language in Requirement R2, Part 2.3 “. . . for external routable protocol connections and Dial-up Connectivity . . .” was included to acknowledge the support given in FERC Order 761, paragraph 87, for electronic security perimeter protections “of some form” to be applied to all BES Cyber Systems, regardless of impact. Part 2.3 uses the phrase “external routable protocol connections” instead of the defined term “External Routable Connectivity,” because the latter term has very specific connotations relating to Electronic Security Perimeters and high and medium impact BES Cyber Systems. Using the glossary term “External Routable Connectivity” in the context of Requirement R2 would not be appropriate because Requirement R2 is limited in scope to low impact BES Cyber Systems.

Review and approval of the cyber security policy at least every 15 calendar months ensures that the policy is kept up-to-date and periodically reaffirms management's commitment to the protection of its BES Cyber Systems.

Rationale for R3:

The identification and documentation of the single CIP Senior Manager ensures that there is clear authority and ownership for the CIP program within an organization, as called for in Blackout Report Recommendation 43. The language that identifies CIP Senior Manager responsibilities is included in the *Glossary of Terms used in NERC Reliability Standards* so that it may be used across the body of CIP standards without an explicit cross-reference.

FERC Order No. 706, Paragraph 296, requests consideration of whether the single senior manager should be a corporate officer or equivalent. As implicated through the defined term, the senior manager has “the overall authority and responsibility for leading and managing implementation of the requirements within this set of standards” which ensures that the senior manager is of sufficient position in the Responsible Entity to ensure that cyber security receives the prominence that is necessary. In addition, given the range of business models for responsible entities, from municipal, cooperative, federal agencies, investor owned utilities, privately owned utilities, and everything in between, the SDT believes that requiring the senior manager to be a “corporate officer or equivalent” would be extremely difficult to interpret and enforce on a consistent basis.

Rationale for R4:

The intent of the requirement is to ensure clear accountability within an organization for certain security matters. It also ensures that delegations are kept up-to-date and that individuals do not assume undocumented authority.

In FERC Order No. 706, Paragraphs 379 and 381, the Commission notes that Recommendation 43 of the 2003 Blackout Report calls for “clear lines of authority and ownership for security matters.” With this in mind, the Standard Drafting Team has sought to provide clarity in the requirement for delegations so that this line of authority is clear and apparent from the documented delegations.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	Update to conform to changes to CIP-002-4 (Project 2008-06)
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-003-5. (Order becomes effective 2/3/14.)	
<u>5(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial</u>

			<u>Action Scheme and RAS</u>
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A. Introduction

1. **Title:** Cyber Security — Personnel & Training
2. **Number:** CIP-004-5.1(X)
3. **Purpose:** To minimize the risk against compromise that could lead to misoperation or instability in the BES from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.

4. Applicability:

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

- 4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
- 4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-004-5.1(X):

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-004-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-004-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-004-5.1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X) and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-5.1(X) Table R1 – Security Awareness Program			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity’s personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Systems.	An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: <ul style="list-style-type: none"> • direct communications (for example, e-mails, memos, computer-based training); or • indirect communications (for example, posters, intranet, or brochures); or • management support and reinforcement (for example, presentations or meetings).

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program*. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M2.** Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-5.1(X) Table R2 – Cyber Security Training Program			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Training content on:</p> <ol style="list-style-type: none"> 2.1.1. Cyber security policies; 2.1.2. Physical access controls; 2.1.3. Electronic access controls; 2.1.4. The visitor control program; 2.1.5. Handling of BES Cyber System Information and its storage; 2.1.6. Identification of a Cyber Security Incident and initial notifications in accordance with the entity’s incident response plan; 2.1.7. Recovery plans for BES Cyber Systems; 2.1.8. Response to Cyber Security Incidents; and 2.1.9. Cyber security risks associated with a BES Cyber System’s electronic interconnectivity and interoperability with other Cyber Assets. 	<p>Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.</p>

CIP-004-5.1(X) Table R2 – Cyber Security Training Program			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Require completion of the training specified in Part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable Cyber Assets, except during CIP Exceptional Circumstances.</p>	<p>Examples of evidence may include, but are not limited to, training records and documentation of when CIP Exceptional Circumstances were invoked.</p>
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Require completion of the training specified in Part 2.1 at least once every 15 calendar months.</p>	<p>Examples of evidence may include, but are not limited to, dated individual training records.</p>

R3. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented personnel risk assessment programs to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

M3. Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	Process to confirm identity.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to confirm identity.

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes:</p> <ol style="list-style-type: none"> 3.2.1. current residence, regardless of duration; and 3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive months or more. <p>If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to perform a seven year criminal history records check.</p>

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Criteria or process to evaluate criminal history records checks for authorizing access.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to evaluate criminal history records checks.</p>
3.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to Parts 3.1 through 3.3.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s criteria or process for verifying contractors or service vendors personnel risk assessments.</p>

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed according to Parts 3.1 to 3.4 within the last seven years.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process for ensuring that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.</p>

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access management programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M4.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

CIP-004-5.1(X) Table R4 – Access Management Program			
Part	Applicable Systems	Requirements	Measures
4.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances:</p> <ol style="list-style-type: none"> 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; and 4.1.3. Access to designated storage locations, whether physical or electronic, for BES Cyber System Information. 	<p>An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a Physical Security Perimeter, and access to designated storage locations, whether physical or electronic, for BES Cyber System Information.</p>

CIP-004-5.1(X) Table R4 – Access Management Program			
Part	Applicable Systems	Requirements	Measures
4.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or • Dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).

CIP-004-5.1(X) Table R4 – Access Management Program			
Part	Applicable Systems	Requirements	Measures
4.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>For electronic access, verify at least once every 15 calendar months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.</p>	<p>An example of evidence may include, but is not limited to, documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> 1. A dated listing of all accounts/account groups or roles within the system; 2. A summary description of privileges associated with each group or role; 3. Accounts assigned to the group or role; and 4. Dated evidence showing verification of the privileges for the group are authorized and appropriate to the work function performed by people assigned to each account.

CIP-004-5.1(X) Table R4 – Access Management Program			
Part	Applicable Systems	Requirements	Measures
4.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Verify at least once every 15 calendar months that access to the designated storage locations for BES Cyber System Information, whether physical or electronic, are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.</p>	<p>An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> 1. A dated listing of authorizations for BES Cyber System information; 2. Any privileges associated with the authorizations; and 3. Dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access revocation programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Planning].
- M5.** Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>A process to initiate removal of an individual’s ability for unescorted physical access and Interactive Remote Access upon a termination action, and complete the removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).</p>	<p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> 1. Dated workflow or sign-off form verifying access removal associated with the termination action; and 2. Logs or other demonstration showing such persons no longer have access.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>For reassignments or transfers, revoke the individual’s authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next calendar day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p>	<p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> 1. Dated workflow or sign-off form showing a review of logical and physical access; and 2. Logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>For termination actions, revoke the individual’s access to the designated storage locations for BES Cyber System Information, whether physical or electronic (unless already revoked according to Requirement R5.1), by the end of the next calendar day following the effective date of the termination action.</p>	<p>An example of evidence may include, but is not limited to, workflow or sign-off form verifying access removal to designated physical areas or cyber systems containing BES Cyber System Information associated with the terminations and dated within the next calendar day of the termination action.</p>

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.4	High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> EACMS 	For termination actions, revoke the individual’s non-shared user accounts (unless already revoked according to Parts 5.1 or 5.3) within 30 calendar days of the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or sign-off form showing access removal for any individual BES Cyber Assets and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.5	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> EACMS 	<p>For termination actions, change passwords for shared account(s) known to the user within 30 calendar days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 calendar days following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p> <p>If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 calendar days following the end of the operating circumstances.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> Workflow or sign-off form showing password reset within 30 calendar days of the termination; Workflow or sign-off form showing password reset within 30 calendar days of the reassignments or transfers; or Documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 calendar days following the end of the operating circumstance.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so less than 10 calendar days after the start of a subsequent calendar quarter. (1.1)	The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so between 10 and 30 calendar days after the start of a subsequent calendar quarter. (1.1)	The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so within the subsequent quarter but beyond 30 calendar days after the start of that calendar quarter. (1.1)	The Responsible Entity did not document or implement any security awareness process(es) to reinforce cyber security practices. (R1) OR The Responsible Entity did not reinforce cyber security practices and associated physical security practices for at least two consecutive calendar quarters. (1.1)
R2	Operations Planning	Lower	The Responsible Entity implemented a cyber security training program but failed to include one of the training	The Responsible Entity implemented a cyber security training program but failed to include two of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess	The Responsible Entity implemented a cyber security training program but failed to include three of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess	The Responsible Entity did not implement a cyber security training program appropriate to individual roles, functions, or responsibilities. (R2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized</p>	<p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals with authorized</p>	<p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals with authorized electronic or authorized</p>	<p>The Responsible Entity implemented a cyber security training program but failed to include four or more of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion</p>	<p>electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p>	<p>unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p>	<p>identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			date, and did not identify, assess and correct the deficiencies. (2.3)			
R3	Operations Planning	Medium	<p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access</p>	<p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for two individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p>	<p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for three individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p>	<p>The Responsible Entity did not have all of the required elements as described by 3.1 through 3.4 included within documented program(s) for implementing Personnel Risk Assessments (PRAs), for individuals, including contractors and service vendors, for obtaining and retaining authorized cyber or authorized unescorted physical access. (R3)</p> <p>OR</p> <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			for one individual, and did not identify, assess, and correct the deficiencies. (R3) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for one	contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for two individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for two individuals, and did not identify, assess, and	contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for three individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for three individuals, and did not identify, assess, and	for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for four or more individuals, and did not identify, assess, and correct the deficiencies. (R3) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			individual, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required	correct the deficiencies. (3.2 & 3.4) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for two individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4) OR The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for two individuals with authorized electronic or authorized unescorted	correct the deficiencies. (3.2 & 3.4) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for three individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4) OR The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for three individuals with authorized electronic or authorized unescorted	OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.2 & 3.4) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>checks described in 3.2.1 and 3.2.2 for one individual, and did not identify, assess, and correct the deficiencies. (3.2 & 3.4)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access</p>	<p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p>	<p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p>	<p>authorized unescorted physical access but did not evaluate criminal history records check for access authorization for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)</p> <p>OR</p> <p>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for four or more individuals with authorized electronic or authorized unescorted physical access within 7 calendar years of the previous PRA completion date and has identified deficiencies, and did not identify, assess, and correct the deficiencies. (3.5)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			but did not evaluate criminal history records check for access authorization for one individual, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4) OR The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for one individual with authorized electronic or authorized unescorted physical access within 7			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)			
R4	Operations Planning and Same Day Operations	Medium	The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so less than 10 calendar days after the start	The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 10 and 20 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2) OR	The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 20 and 30 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2) OR	The Responsible Entity did not implement any documented program(s) for access management. (R4) OR The Responsible Entity has implemented one or more documented program(s) for access management that includes a process to authorize electronic access, unescorted physical access, or access to the designated storage locations where

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>of a subsequent calendar quarter, and did not identify, assess and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15</p>	<p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for two BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p>	<p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for three BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p>	<p>BES Cyber System Information is located, and did not identify, assess, and correct the deficiencies. (4.1)</p> <p>OR</p> <p>The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records for at least two consecutive calendar quarters, and did not identify, assess, and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar months of the previous verification but for one BES Cyber System, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.3) OR The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is	calendar months of the previous verification but for two BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)	calendar months of the previous verification but for three BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)	privileges are correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3) OR The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber System Information storage locations, privileges

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			correct and necessary within 15 calendar months of the previous verification but for one BES Cyber System Information storage location, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.4)			were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)
R5	Same Day Operations and Operations Planning	Medium	The Responsible Entity has implemented one or more process(es) to revoke the individual's	The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or	The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or	The Responsible Entity has not implemented any documented program(s) for access revocation for electronic access, unescorted physical access, or BES Cyber System

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>access to the designated storage locations for BES Cyber System Information but, for one individual, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> <p>OR</p> <p>The Responsible Entity has implemented</p>	<p>complete the removal within 24 hours of the termination action but did not initiate those removals for one individual, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for one individual, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p>	<p>complete the removal within 24 hours of the termination action but did not initiate those removals for two individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for two individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p>	<p>Information storage locations. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or complete the removal within 24 hours of the termination action but did not initiate those removals for three or more individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>one or more process(es) to revoke the individual’s user accounts upon termination action but did not do so for within 30 calendar days of the date of termination action for one or more individuals, and did not identify, assess, and correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to</p>	<p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for two individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p>	<p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for three or more individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p>	<p>requires retention of access following reassignments or transfers but, for three or more individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			change passwords for shared accounts known to the user upon termination action, reassignment, or transfer, but did not do so for within 30 calendar days of the date of termination action, reassignment, or transfer for one or more individuals, and did not identify, assess, and correct the deficiencies. (5.5) OR The Responsible			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Entity has implemented one or more process(es) to determine and document extenuating operating circumstances following a termination action, reassignment, or transfer, but did not change one or more passwords for shared accounts known to the user within 10 calendar days following the end of the extenuating operating circumstances, and did not			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			identify, assess, and correct the deficiencies. (5.5)			

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)'s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The security awareness program is intended to be an informational program, not a formal training program. It should reinforce security practices to ensure that personnel maintain awareness of best practices for both physical and electronic security to protect its BES Cyber Systems. The Responsible Entity is not required to provide records that show that each individual received or understood the information, but they must maintain documentation of the program materials utilized in the form of posters, memos, and/or presentations.

Examples of possible mechanisms and evidence, when dated, which can be used are:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

Requirement R2:

Training shall cover the policies, access controls, and procedures as developed for the BES Cyber Systems and include, at a minimum, the required items appropriate to personnel roles and responsibilities from Table R2. The Responsible Entity has the flexibility to define the training program and it may consist of multiple modules and multiple delivery mechanisms, but a single training program for all individuals needing to be trained is acceptable. The training can focus on functions, roles or responsibilities at the discretion of the Responsible Entity.

One new element in the training content is intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems as per FERC Order No. 706, Paragraph 434. This is not intended to provide technical training to individuals supporting networking hardware and software, but educating system users of the cyber security risks associated with the interconnectedness of these systems. The users, based on their function, role or responsibility, should have a basic understanding of which systems can be accessed from other systems and how the actions they take can affect cyber security.

Each Responsible Entity shall ensure all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, complete cyber security training prior to their being granted authorized access, except for CIP Exceptional Circumstances. To retain the authorized accesses, individuals must complete the training at least one every 15 months.

Requirement R3:

Each Responsible Entity shall ensure a personnel risk assessment is performed for all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, prior to their being granted authorized access, except for program specified exceptional circumstances that are approved by the single senior management official or their delegate and impact the reliability of the BES or emergency response. Identity should be confirmed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. Identity only needs to be confirmed prior to initially granting access and only requires periodic confirmation according to the entity's process during the tenure of employment, which may or may not be the same as the initial verification action.

A seven year criminal history check should be performed for those locations where the individual has resided for at least six consecutive months. This check should also be performed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. When it is not possible to perform a full seven year criminal history check, documentation must be made of what criminal history check was performed, and the reasons a full seven-year check could not be performed. Examples of this could include

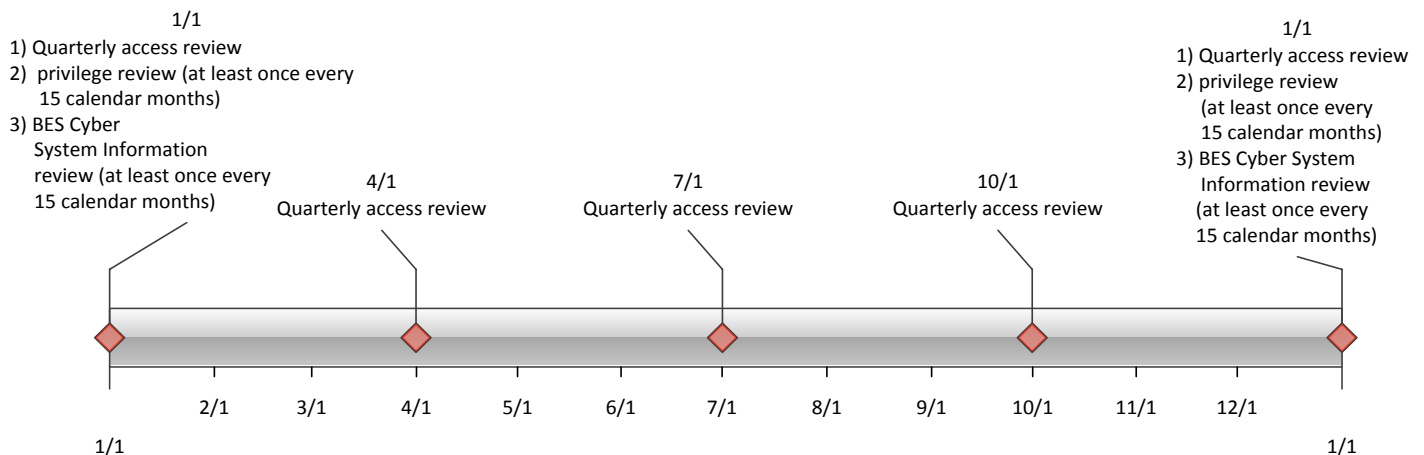
individuals under the age of 25 where a juvenile criminal history may be protected by law, individuals who may have resided in locations from where it is not possible to obtain a criminal history records check, violates the law or is not allowed under the existing collective bargaining agreement. The Responsible Entity should consider the absence of information for the full seven years when assessing the risk of granting access during the process to evaluate the criminal history check. There needs to be a personnel risk assessment that has been completed within the last seven years for each individual with access. A new criminal history records check must be performed as part of the new PRA. Individuals who have been granted access under a previous version of these standards need a new PRA within seven years of the date of their last PRA. The clarifications around the seven year criminal history check in this version do not require a new PRA be performed by the implementation date.

Requirement R4:

Authorization for electronic and unescorted physical access and access to BES Cyber System Information must be on the basis of necessity in the individual performing a work function. Documentation showing the authorization should have some justification of the business need included. To ensure proper segregation of duties, access authorization and provisioning should not be performed by the same person where possible.

This requirement specifies both quarterly reviews and reviews at least once every 15 calendar months. Quarterly reviews are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

The privilege review at least once every 15 calendar months is more detailed to ensure an individual’s associated privileges are the minimum necessary to perform their work function



(i.e., least privilege). Entities can more efficiently perform this review by implementing role-based access. This involves determining the specific roles on the system (e.g., system operator, technician, report viewer, administrator, etc.) then grouping access privileges to the role and assigning users to the role. Role-based access does not assume any specific software and can be implemented by defining specific provisioning processes for each role where access group assignments cannot be performed. Role-based access permissions eliminate the need to perform the privilege review on individual accounts. An example timeline of all the reviews in Requirement R4 is included below.

Separation of duties should be considered when performing the reviews in Requirement R4. The person reviewing should be different than the person provisioning access.

If the results of quarterly or at least once every 15 calendar months account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that this error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

Requirement R5:

The requirement to revoke access at the time of the termination action includes procedures showing revocation of access concurrent with the termination action. This requirement recognizes that the timing of the termination action may vary depending on the circumstance. Some common scenarios and possible processes on when the termination action occurs are provided in the following table. These scenarios are not an exhaustive list of all scenarios, but are representative of several routine business practices.

Scenario	Possible Process
Immediate involuntary termination	Human resources or corporate security escorts the individual off site and the supervisor or human resources personnel notify the appropriate personnel to begin the revocation process.
Scheduled involuntary termination	Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.
Voluntary termination	Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.
Retirement where the last working day is several weeks prior to the termination date	Human resources personnel coordinate with manager to determine the final date access is no longer needed and schedule the revocation of access on the determined day.

Death	Human resources personnel are notified of the death and work with appropriate personnel to begin the revocation process.
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Revocation of electronic access should be understood to mean a process with the end result that electronic access to BES Cyber Systems is no longer possible using credentials assigned to or known by the individual(s) whose access privileges are being revoked. Steps taken to accomplish this outcome may include deletion or deactivation of accounts used by the individual(s), but no specific actions are prescribed. Entities should consider the ramifications of deleting an account may include incomplete event log entries due to an unrecognized account or system services using the account to log on.

The initial revocation required in Requirement R5.1 includes unescorted physical access and Interactive Remote Access. These two actions should prevent any further access by the individual after termination. If an individual still has local access accounts (i.e., accounts on the Cyber Asset itself) on BES Cyber Assets, then the Responsible Entity has 30 days to complete the revocation process for those accounts. However, nothing prevents a Responsible Entity from performing all of the access revocation at the time of termination.

For transferred or reassigned individuals, a review of access privileges should be performed. This review could entail a simple listing of all authorizations for an individual and working with the respective managers to determine which access will still be needed in the new position. For instances in which the individual still needs to retain access as part of a transitory period, the entity should schedule a time to review these access privileges or include the privileges in the quarterly account review or annual privilege review.

Revocation of access to shared accounts is called out separately to prevent the situation where passwords on substation and generation devices are constantly changed due to staff turnover.

Requirement 5.5 specified that passwords for shared account are to be changed within 30 calendar days of the termination action or when the Responsible Entity determines an individual no longer requires access to the account as a result of a reassignment or transfer. The 30 days applies under normal operating conditions. However, circumstances may occur where this is not possible. Some systems may require an outage or reboot of the system in order to complete the password change. In periods of extreme heat or cold, many Responsible Entities may prohibit system outages and reboots in order to maintain reliability of the BES. When these circumstances occur, the Responsible Entity must document these circumstances and prepare to change the password within 10 calendar days following the end of the operating circumstances. Records of activities must be retained to show that the Responsible Entity followed the plan they created.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

Ensures that Responsible Entities with personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Assets take action so that those personnel with such authorized electronic or authorized unescorted physical access maintain awareness of the Responsible Entity's security practices.

Summary of Changes: Reformatted into table structure.

Reference to prior version: (Part 1.1) CIP-004-4, R1

Change Rationale: (Part 1.1)

Changed to remove the need to ensure or prove everyone with authorized electronic or authorized unescorted physical access "received" ongoing reinforcement – to state that security awareness has been reinforced.

Moved example mechanisms to guidance.

Rationale for R2:

To ensure that the Responsible Entity's training program for personnel who need authorized electronic access and/or authorized unescorted physical access to BES Cyber Systems covers the proper policies, access controls, and procedures to protect BES Cyber Systems and are trained before access is authorized.

Based on their role, some personnel may not require training on all topics.

Summary of Changes:

1. Addition of specific role training for:

- The visitor control program
- Electronic interconnectivity supporting the operation and control of BES Cyber Systems
- Storage media as part of the handling of BES Cyber Systems information

2. Change references from Critical Cyber Assets to BES Cyber Systems.

Reference to prior version: (Part 2.1) CIP004-4, R2.2.1

Change Rationale: (Part 2.1)

Removed "proper use of Critical Cyber Assets" concept from previous versions to focus the requirement on cyber security issues, not the business function. The previous version was

focused more on the business or functional use of the BES Cyber System and is outside the scope of cyber security. Personnel who will administer the visitor control process or serve as escorts for visitors need training on the program. Core training on the handling of BES Cyber System (not Critical Cyber Assets) Information, with the addition of storage; FERC Order No. 706, paragraph 413 and paragraphs 632-634, 688, 732-734; DHS 2.4.16. Core training on the identification and reporting of a Cyber Security Incident; FERC Order No. 706, Paragraph 413; Related to CIP-008-5(X) & DHS Incident Reporting requirements for those with roles in incident reporting. Core training on the action plans and procedures to recover or re-establish BES Cyber Systems for personnel having a role in the recovery; FERC Order No. 706, Paragraph 413. Core training programs are intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems; FERC Order No. 706, Paragraph 434.

Reference to prior version: (Part 2.2) CIP004-4, R2.1

Change Rationale: (Part 2.2)

Addition of exceptional circumstances parameters as directed in FERC Order No. 706, Paragraph 431 is detailed in CIP-003-5(X).

Reference to prior version: (Part 2.3) CIP004-4, R2.3

Change Rationale: (Part 2.3)

Updated to replace “annually” with “once every 15 calendar months.”

Rationale for R3:

To ensure that individuals who need authorized electronic or authorized unescorted physical access to BES Cyber Systems have been assessed for risk. Whether initial access or maintaining access, those with access must have had a personnel risk assessment completed within the last 7 years.

Summary of Changes: Specify that the seven year criminal history check covers all locations where the individual has resided for six consecutive months or more, including current residence regardless of duration.

Reference to prior version: (Part 3.1) CIP004-4, R3.1

Change Rationale: (Part 3.1)

Addressed interpretation request in guidance. Specified that process for identity confirmation is required. The implementation plan clarifies that a documented identity verification conducted under an earlier version of the CIP standards is sufficient.

Reference to prior version: (Part 3.2) CIP004-4, R3.1

Change Rationale: (Part 3.2)

Specify that the seven year criminal history check covers all locations where the individual has resided for six months or more, including current residence regardless of duration. Added

additional wording based on interpretation request. Provision is made for when a full seven-year check cannot be performed.

Reference to prior version: (Part 3.3) New

Change Rationale: (Part 3.3)

There should be documented criteria or a process used to evaluate criminal history records checks for authorizing access.

Reference to prior version: (Part 3.4) CIP-004-4, R3.3

Change Rationale: (Part 3.4)

Separated into its own table item.

Reference to prior version: (Part 3.5) CIP-004-3, R3, R3.3

Change Rationale: (Part 3.5)

Whether for initial access or maintaining access, establishes that those with access must have had PRA completed within 7 years. This covers both initial and renewal. The implementation plan specifies that initial performance of this requirement is 7 years after the last personnel risk assessment that was performed pursuant to a previous version of the CIP Cyber Security Standards for a personnel risk assessment. CIP-004-3, R3, R3.3

Rationale for R4:

To ensure that individuals with access to BES Cyber Systems and the physical and electronic locations where BES Cyber System Information is stored by the Responsible Entity have been properly authorized for such access. "Authorization" should be considered to be a grant of permission by a person or persons empowered by the Responsible Entity to perform such grants and included in the delegations referenced in CIP-003-5(X). "Provisioning" should be considered the actions to provide access to an individual.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (i.e., physical access control system, remote access system, directory services).

CIP Exceptional Circumstances are defined in a Responsible Entity's policy from CIP-003-5(X) and allow an exception to the requirement for authorization to BES Cyber Systems and BES Cyber System Information.

Quarterly reviews in Part 4.5 are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to access the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account

databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

If the results of quarterly or annual account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that the error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

Summary of Changes: The primary change was in pulling the access management requirements from CIP-003-4, CIP-004-4, and CIP-007-4 into a single requirement. The requirements from Version 4 remain largely unchanged except to clarify some terminology. The purpose for combining these requirements is to remove the perceived redundancy in authorization and review. The requirement in CIP-004-4 R4 to maintain a list of authorized personnel has been removed because the list represents only one form of evidence to demonstrate compliance that only authorized persons have access.

Reference to prior version: (Part 4.1) CIP 003-4, R5.1 and R5.2; CIP-006-4, R1.5 and R4; CIP-007-4, R5.1 and R5.1.1

Change Rationale: (Part 4.1)

Combined requirements from CIP-003-4, CIP-007-4, and CIP-006-4 to make the authorization process clear and consistent. *CIP-003-4, CIP-004-4, CIP-006-4, and CIP-007-4 all reference authorization of access in some form, and CIP-003-4 and CIP-007-4 require authorization on a “need to know” basis or with respect to work functions performed. These were consolidated to ensure consistency in the requirement language.*

Reference to prior version: (Part 4.2) CIP 004-4, R4.1

Change Rationale: (Part 4.2)

Feedback among team members, observers, and regional CIP auditors indicates there has been confusion in implementation around what the term “review” entailed in CIP-004-4, Requirement R4.1. This requirement clarifies the review should occur between the provisioned access and authorized access.

Reference to prior version: (Part 4.3) CIP 007-4, R5.1.3

Change Rationale: (Part 4.3)

Moved requirements to ensure consistency and eliminate the cross-referencing of requirements. Clarified what was necessary in performing verification by stating the objective was to confirm that access privileges are correct and the minimum necessary.

Reference to prior version: (Part 4.4) CIP-003-4, R5.1.2

Change Rationale: (Part 4.4)

Moved requirement to ensure consistency among access reviews. Clarified precise meaning of annual. Clarified what was necessary in performing a verification by stating the objective was to

confirm access privileges are correct and the minimum necessary for performing assigned work functions.

Rationale for R5:

The timely revocation of electronic access to BES Cyber Systems is an essential element of an access management regime. When an individual no longer requires access to a BES Cyber System to perform his or her assigned functions, that access should be revoked. This is of particular importance in situations where a change of assignment or employment is involuntary, as there is a risk the individual(s) involved will react in a hostile or destructive manner.

In considering how to address directives in FERC Order No. 706 directing “immediate” revocation of access for involuntary separation, the SDT chose not to specify hourly time parameters in the requirement (e.g., revoking access within 1 hour). The point in time at which an organization terminates a person cannot generally be determined down to the hour. However, most organizations have formal termination processes, and the timeliest revocation of access occurs in concurrence with the initial processes of termination.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (e.g., physical access control system, remote access system, directory services).

Summary of Changes: FERC Order No. 706, Paragraphs 460 and 461, state the following: “The Commission adopts the CIP NOPR proposal to direct the ERO to develop modifications to CIP-004-1 to require immediate revocation of access privileges when an employee, contractor or vendor no longer performs a function that requires physical or electronic access to a Critical Cyber Asset for any reason (including disciplinary action, transfer, retirement, or termination).

As a general matter, the Commission believes that revoking access when an employee no longer needs it, either because of a change in job or the end of employment, must be immediate.”

Reference to prior version: (Part 5.1) CIP 004-4, R4.2

Change Rationale: (Part 5.1)

*The FERC Order No. 706, Paragraphs 460 and 461, directs modifications to the Standards to **require immediate revocation** for any person no longer needing access. To address this directive, this requirement specifies revocation concurrent with the termination instead of within 24 hours.*

Reference to prior version: (Part 5.2) CIP-004-4, R4.2

Change Rationale: (Part 5.2)

FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access, including transferred employees. In reviewing how to modify this requirement, the SDT determined the date a person no longer needs access after a transfer was problematic because the need may change over time. As a result, the SDT adapted this requirement from NIST 800-53 Version 3 to review access authorizations on the date of the transfer. The SDT felt this was a more effective control in accomplishing the objective to prevent a person from accumulating unnecessary authorizations through transfers.

Reference to prior version: (Part 5.3) New

Change Rationale: (Part 5.3)

FERC Order No. 706, Paragraph 386, directs modifications to the standards to require prompt revocation of access to protected information. To address this directive, Responsible Entities are required to revoke access to areas designated for BES Cyber System Information. This could include records closets, substation control houses, records management systems, file shares or other physical and logical areas under the Responsible Entity's control.

Reference to prior version: (Part 5.4) New

Change Rationale: (Part 5.4)

FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access. In order to meet the immediate timeframe, Responsible Entities will likely have initial revocation procedures to prevent remote and physical access to the BES Cyber System. Some cases may take more time to coordinate access revocation on individual Cyber Assets and applications without affecting reliability. This requirement provides the additional time to review and complete the revocation process. Although the initial actions already prevent further access, this step provides additional assurance in the access revocation process.

Reference to prior version: (Part 5.5) CIP-007-4, R5.2.3

Change Rationale: (Part 5.5)

To provide clarification of expected actions in managing the passwords.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Modified two VSLs in R4.	Errata
5.1	11/22/13	FERC Order issued approving CIP-004-5.1. (Order becomes effective on 2/3/14.)	
5.1	4/2/14	Address FERC Order 791 directive to modify Requirement R4 VRF and VSLs	R4-VRF and VSLs

Guidelines and Technical Basis

5.1	5/6/14	The NERC Board of Trustees adopted a revision to the VRF of Requirement 4 from Lower to Medium in CIP-004-5.1.	
5.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — Personnel & Training
2. **Number:** CIP-004-5.1(X)
3. **Purpose:** To minimize the risk against compromise that could lead to misoperation or instability in the BES from individuals accessing BES Cyber Systems by requiring an appropriate level of personnel risk assessment, training, and security awareness in support of protecting BES Cyber Systems.

4. Applicability:

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

- 4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
- 4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-004-5.1(X):

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-004-5.1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-004-5.1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-004-5.1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X) and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of

implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R1 – Security Awareness Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-5.1(X) Table R1 – Security Awareness Program			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Security awareness that, at least once each calendar quarter, reinforces cyber security practices (which may include associated physical security practices) for the Responsible Entity’s personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Systems.	An example of evidence may include, but is not limited to, documentation that the quarterly reinforcement has been provided. Examples of evidence of reinforcement may include, but are not limited to, dated copies of information used to reinforce security awareness, as well as evidence of distribution, such as: <ul style="list-style-type: none"> • direct communications (for example, e-mails, memos, computer-based training); or • indirect communications (for example, posters, intranet, or brochures); or • management support and reinforcement (for example, presentations or meetings).

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, a cyber security training program(s) appropriate to individual roles, functions, or responsibilities that collectively includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program*. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- M2.** Evidence must include the training program that includes each of the applicable requirement parts in *CIP-004-5.1(X) Table R2 – Cyber Security Training Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-5.1(X) Table R2 – Cyber Security Training Program			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Training content on:</p> <ol style="list-style-type: none"> 2.1.1. Cyber security policies; 2.1.2. Physical access controls; 2.1.3. Electronic access controls; 2.1.4. The visitor control program; 2.1.5. Handling of BES Cyber System Information and its storage; 2.1.6. Identification of a Cyber Security Incident and initial notifications in accordance with the entity’s incident response plan; 2.1.7. Recovery plans for BES Cyber Systems; 2.1.8. Response to Cyber Security Incidents; and 2.1.9. Cyber security risks associated with a BES Cyber System’s electronic interconnectivity and interoperability with other Cyber Assets. 	<p>Examples of evidence may include, but are not limited to, training material such as power point presentations, instructor notes, student notes, handouts, or other training materials.</p>

CIP-004-5.1(X) Table R2 – Cyber Security Training Program			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Require completion of the training specified in Part 2.1 prior to granting authorized electronic access and authorized unescorted physical access to applicable Cyber Assets, except during CIP Exceptional Circumstances.</p>	<p>Examples of evidence may include, but are not limited to, training records and documentation of when CIP Exceptional Circumstances were invoked.</p>
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Require completion of the training specified in Part 2.1 at least once every 15 calendar months.</p>	<p>Examples of evidence may include, but are not limited to, dated individual training records.</p>

R3. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented personnel risk assessment programs to attain and retain authorized electronic or authorized unescorted physical access to BES Cyber Systems that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

M3. Evidence must include the documented personnel risk assessment programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program* and additional evidence to demonstrate implementation of the program(s).

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	Process to confirm identity.	An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to confirm identity.

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Process to perform a seven year criminal history records check as part of each personnel risk assessment that includes:</p> <ol style="list-style-type: none"> 3.2.1. current residence, regardless of duration; and 3.2.2. other locations where, during the seven years immediately prior to the date of the criminal history records check, the subject has resided for six consecutive months or more. <p>If it is not possible to perform a full seven year criminal history records check, conduct as much of the seven year criminal history records check as possible and document the reason the full seven year criminal history records check could not be performed.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to perform a seven year criminal history records check.</p>

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Criteria or process to evaluate criminal history records checks for authorizing access.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process to evaluate criminal history records checks.</p>
3.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Criteria or process for verifying that personnel risk assessments performed for contractors or service vendors are conducted according to Parts 3.1 through 3.3.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s criteria or process for verifying contractors or service vendors personnel risk assessments.</p>

CIP-004-5.1(X) Table R3 – Personnel Risk Assessment Program			
Part	Applicable Systems	Requirements	Measures
3.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Process to ensure that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed according to Parts 3.1 to 3.4 within the last seven years.</p>	<p>An example of evidence may include, but is not limited to, documentation of the Responsible Entity’s process for ensuring that individuals with authorized electronic or authorized unescorted physical access have had a personnel risk assessment completed within the last seven years.</p>

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access management programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M4.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R4 – Access Management Program* and additional evidence to demonstrate that the access management program was implemented as described in the Measures column of the table.

CIP-004-5.1(X) Table R4 – Access Management Program

Part	Applicable Systems	Requirements	Measures
4.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Process to authorize based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances:</p> <ol style="list-style-type: none"> 4.1.1. Electronic access; 4.1.2. Unescorted physical access into a Physical Security Perimeter; and 4.1.3. Access to designated storage locations, whether physical or electronic, for BES Cyber System Information. 	<p>An example of evidence may include, but is not limited to, dated documentation of the process to authorize electronic access, unescorted physical access in a Physical Security Perimeter, and access to designated storage locations, whether physical or electronic, for BES Cyber System Information.</p>

CIP-004-5.1(X) Table R4 – Access Management Program

Part	Applicable Systems	Requirements	Measures
4.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Verify at least once each calendar quarter that individuals with active electronic access or unescorted physical access have authorization records.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Dated documentation of the verification between the system generated list of individuals who have been authorized for access (i.e., workflow database) and a system generated list of personnel who have access (i.e., user account listing), or • Dated documentation of the verification between a list of individuals who have been authorized for access (i.e., authorization forms) and a list of individuals provisioned for access (i.e., provisioning forms or shared account listing).

CIP-004-5.1(X) Table R4 – Access Management Program			
Part	Applicable Systems	Requirements	Measures
4.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>For electronic access, verify at least once every 15 calendar months that all user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and are those that the Responsible Entity determines are necessary.</p>	<p>An example of evidence may include, but is not limited to, documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> 1. A dated listing of all accounts/account groups or roles within the system; 2. A summary description of privileges associated with each group or role; 3. Accounts assigned to the group or role; and 4. Dated evidence showing verification of the privileges for the group are authorized and appropriate to the work function performed by people assigned to each account.

CIP-004-5.1(X) Table R4 – Access Management Program

Part	Applicable Systems	Requirements	Measures
4.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Verify at least once every 15 calendar months that access to the designated storage locations for BES Cyber System Information, whether physical or electronic, are correct and are those that the Responsible Entity determines are necessary for performing assigned work functions.</p>	<p>An example of evidence may include, but is not limited to, the documentation of the review that includes all of the following:</p> <ol style="list-style-type: none"> 1. A dated listing of authorizations for BES Cyber System information; 2. Any privileges associated with the authorizations; and 3. Dated evidence showing a verification of the authorizations and any privileges were confirmed correct and the minimum necessary for performing assigned work functions.

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented access revocation programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Planning].
- M5.** Evidence must include each of the applicable documented programs that collectively include each of the applicable requirement parts in *CIP-004-5.1(X) Table R5 – Access Revocation* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>A process to initiate removal of an individual’s ability for unescorted physical access and Interactive Remote Access upon a termination action, and complete the removals within 24 hours of the termination action (Removal of the ability for access may be different than deletion, disabling, revocation, or removal of all access rights).</p>	<p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> 1. Dated workflow or sign-off form verifying access removal associated with the termination action; and 2. Logs or other demonstration showing such persons no longer have access.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>For reassignments or transfers, revoke the individual’s authorized electronic access to individual accounts and authorized unescorted physical access that the Responsible Entity determines are not necessary by the end of the next calendar day following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p>	<p>An example of evidence may include, but is not limited to, documentation of all of the following:</p> <ol style="list-style-type: none"> 1. Dated workflow or sign-off form showing a review of logical and physical access; and 2. Logs or other demonstration showing such persons no longer have access that the Responsible Entity determines is not necessary.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>For termination actions, revoke the individual’s access to the designated storage locations for BES Cyber System Information, whether physical or electronic (unless already revoked according to Requirement R5.1), by the end of the next calendar day following the effective date of the termination action.</p>	<p>An example of evidence may include, but is not limited to, workflow or sign-off form verifying access removal to designated physical areas or cyber systems containing BES Cyber System Information associated with the terminations and dated within the next calendar day of the termination action.</p>

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.4	High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> EACMS 	For termination actions, revoke the individual’s non-shared user accounts (unless already revoked according to Parts 5.1 or 5.3) within 30 calendar days of the effective date of the termination action.	An example of evidence may include, but is not limited to, workflow or sign-off form showing access removal for any individual BES Cyber Assets and software applications as determined necessary to completing the revocation of access and dated within thirty calendar days of the termination actions.

CIP-004-5.1(X) Table R5 – Access Revocation			
Part	Applicable Systems	Requirements	Measures
5.5	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> EACMS 	<p>For termination actions, change passwords for shared account(s) known to the user within 30 calendar days of the termination action. For reassignments or transfers, change passwords for shared account(s) known to the user within 30 calendar days following the date that the Responsible Entity determines that the individual no longer requires retention of that access.</p> <p>If the Responsible Entity determines and documents that extenuating operating circumstances require a longer time period, change the password(s) within 10 calendar days following the end of the operating circumstances.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> Workflow or sign-off form showing password reset within 30 calendar days of the termination; Workflow or sign-off form showing password reset within 30 calendar days of the reassignments or transfers; or Documentation of the extenuating operating circumstance and workflow or sign-off form showing password reset within 10 calendar days following the end of the operating circumstance.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so less than 10 calendar days after the start of a subsequent calendar quarter. (1.1)	The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so between 10 and 30 calendar days after the start of a subsequent calendar quarter. (1.1)	The Responsible Entity did not reinforce cyber security practices during a calendar quarter but did so within the subsequent quarter but beyond 30 calendar days after the start of that calendar quarter. (1.1)	The Responsible Entity did not document or implement any security awareness process(es) to reinforce cyber security practices. (R1) OR The Responsible Entity did not reinforce cyber security practices and associated physical security practices for at least two consecutive calendar quarters. (1.1)
R2	Operations Planning	Lower	The Responsible Entity implemented a cyber security training program but failed to include one of the training	The Responsible Entity implemented a cyber security training program but failed to include two of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess	The Responsible Entity implemented a cyber security training program but failed to include three of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess	The Responsible Entity did not implement a cyber security training program appropriate to individual roles, functions, or responsibilities. (R2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized</p>	<p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train two individuals with authorized</p>	<p>and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train three individuals with authorized electronic or authorized</p>	<p>The Responsible Entity implemented a cyber security training program but failed to include four or more of the training content topics in Requirement Parts 2.1.1 through 2.1.9, and did not identify, assess and correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals (with the exception of CIP Exceptional Circumstances) prior to their being granted authorized electronic and authorized unescorted physical access, and did not</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>unescorted physical access, and did not identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train one individual with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion</p>	<p>electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p>	<p>unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p>	<p>identify, assess and correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity implemented a cyber security training program but failed to train four or more individuals with authorized electronic or authorized unescorted physical access within 15 calendar months of the previous training completion date, and did not identify, assess and correct the deficiencies. (2.3)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			date, and did not identify, assess and correct the deficiencies. (2.3)			
R3	Operations Planning	Medium	<p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access</p>	<p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for two individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p>	<p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for three individuals, and did not identify, assess, and correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including</p>	<p>The Responsible Entity did not have all of the required elements as described by 3.1 through 3.4 included within documented program(s) for implementing Personnel Risk Assessments (PRAs), for individuals, including contractors and service vendors, for obtaining and retaining authorized cyber or authorized unescorted physical access. (R3)</p> <p>OR</p> <p>The Responsible Entity has a program for conducting Personnel Risk Assessments (PRAs)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			for one individual, and did not identify, assess, and correct the deficiencies. (R3) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for one	contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for two individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for two individuals, and did not identify, assess, and	contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for three individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for three individuals, and did not identify, assess, and	for individuals, including contractors and service vendors, but did not conduct the PRA as a condition of granting authorized electronic or authorized unescorted physical access for four or more individuals, and did not identify, assess, and correct the deficiencies. (R3) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not confirm identity for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			individual, and did not identify, assess, and correct the deficiencies. (3.1 & 3.4) OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required	correct the deficiencies. (3.2 & 3.4) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for two individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4) OR The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for two individuals with authorized electronic or authorized unescorted	correct the deficiencies. (3.2 & 3.4) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not evaluate criminal history records check for access authorization for three individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4) OR The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for three individuals with authorized electronic or authorized unescorted	OR The Responsible Entity has a process to perform seven-year criminal history record checks for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access but did not include the required checks described in 3.2.1 and 3.2.2 for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.2 & 3.4) OR The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>checks described in 3.2.1 and 3.2.2 for one individual, and did not identify, assess, and correct the deficiencies. (3.2 & 3.4)</p> <p>OR</p> <p>The Responsible Entity did conduct Personnel Risk Assessments (PRAs) for individuals, including contractors and service vendors, with authorized electronic or authorized unescorted physical access</p>	<p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p>	<p>physical access within 7 calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)</p>	<p>authorized unescorted physical access but did not evaluate criminal history records check for access authorization for four or more individuals, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)</p> <p>OR</p> <p>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for four or more individuals with authorized electronic or authorized unescorted physical access within 7 calendar years of the previous PRA completion date and has identified deficiencies, and did not identify, assess, and correct the deficiencies. (3.5)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>but did not evaluate criminal history records check for access authorization for one individual, and did not identify, assess, and correct the deficiencies. (3.3 & 3.4)</p> <p>OR</p> <p>The Responsible Entity did not conduct Personnel Risk Assessments (PRAs) for one individual with authorized electronic or authorized unescorted physical access within 7</p>			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar years of the previous PRA completion date, and did not identify, assess, and correct the deficiencies. (3.5)			
R4	Operations Planning and Same Day Operations	Medium	The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so less than 10 calendar days after the start	The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 10 and 20 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2) OR	The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records during a calendar quarter but did so between 20 and 30 calendar days after the start of a subsequent calendar quarter, and did not identify, assess, and correct the deficiencies. (4.2) OR	The Responsible Entity did not implement any documented program(s) for access management. (R4) OR The Responsible Entity has implemented one or more documented program(s) for access management that includes a process to authorize electronic access, unescorted physical access, or access to the designated storage locations where

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>of a subsequent calendar quarter, and did not identify, assess and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15</p>	<p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for two BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p>	<p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated privileges are correct and necessary within 15 calendar months of the previous verification but for three BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15</p>	<p>BES Cyber System Information is located, and did not identify, assess, and correct the deficiencies. (4.1)</p> <p>OR</p> <p>The Responsible Entity did not verify that individuals with active electronic or active unescorted physical access have authorization records for at least two consecutive calendar quarters, and did not identify, assess, and correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has implemented processes to verify that user accounts, user account groups, or user role categories, and their specific, associated</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar months of the previous verification but for one BES Cyber System, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.3) OR The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is	calendar months of the previous verification but for two BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)	calendar months of the previous verification but for three BES Cyber System Information storage locations, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)	privileges are correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber Systems, privileges were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.3) OR The Responsible Entity has implemented processes to verify that access to the designated storage locations for BES Cyber System Information is correct and necessary within 15 calendar months of the previous verification but for four or more BES Cyber System Information storage locations, privileges

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			correct and necessary within 15 calendar months of the previous verification but for one BES Cyber System Information storage location, privileges were incorrect or unnecessary, and did not identify, assess and correct the deficiencies. (4.4)			were incorrect or unnecessary, and did not identify, assess, and correct the deficiencies. (4.4)
R5	Same Day Operations and Operations Planning	Medium	The Responsible Entity has implemented one or more process(es) to revoke the individual's	The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or	The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or	The Responsible Entity has not implemented any documented program(s) for access revocation for electronic access, unescorted physical access, or BES Cyber System

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>access to the designated storage locations for BES Cyber System Information but, for one individual, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p> <p>OR</p> <p>The Responsible Entity has implemented</p>	<p>complete the removal within 24 hours of the termination action but did not initiate those removals for one individual, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for one individual, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p>	<p>complete the removal within 24 hours of the termination action but did not initiate those removals for two individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer requires retention of access following reassignments or transfers but, for two individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar</p>	<p>Information storage locations. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to remove the ability for unescorted physical access and Interactive Remote Access upon a termination action or complete the removal within 24 hours of the termination action but did not initiate those removals for three or more individuals, and did not identify, assess, and correct the deficiencies. (5.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to determine that an individual no longer</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>one or more process(es) to revoke the individual’s user accounts upon termination action but did not do so for within 30 calendar days of the date of termination action for one or more individuals, and did not identify, assess, and correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to</p>	<p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for two individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p>	<p>day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more process(es) to revoke the individual’s access to the designated storage locations for BES Cyber System Information but, for three or more individuals, did not do so by the end of the next calendar day following the effective date and time of the termination action, and did not identify, assess, and correct the deficiencies. (5.3)</p>	<p>requires retention of access following reassignments or transfers but, for three or more individuals, did not revoke the authorized electronic access to individual accounts and authorized unescorted physical access by the end of the next calendar day following the predetermined date, and did not identify, assess, and correct the deficiencies. (5.2)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			change passwords for shared accounts known to the user upon termination action, reassignment, or transfer, but did not do so for within 30 calendar days of the date of termination action, reassignment, or transfer for one or more individuals, and did not identify, assess, and correct the deficiencies. (5.5) OR The Responsible			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Entity has implemented one or more process(es) to determine and document extenuating operating circumstances following a termination action, reassignment, or transfer, but did not change one or more passwords for shared accounts known to the user within 10 calendar days following the end of the extenuating operating circumstances, and did not			

R #	Time Horizon	VRF	Violation Severity Levels (CIP-004-5.1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			identify, assess, and correct the deficiencies. (5.5)			

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The security awareness program is intended to be an informational program, not a formal training program. It should reinforce security practices to ensure that personnel maintain awareness of best practices for both physical and electronic security to protect its BES Cyber Systems. The Responsible Entity is not required to provide records that show that each individual received or understood the information, but they must maintain documentation of the program materials utilized in the form of posters, memos, and/or presentations.

Examples of possible mechanisms and evidence, when dated, which can be used are:

- Direct communications (e.g., emails, memos, computer based training, etc.);
- Indirect communications (e.g., posters, intranet, brochures, etc.);
- Management support and reinforcement (e.g., presentations, meetings, etc.).

Requirement R2:

Training shall cover the policies, access controls, and procedures as developed for the BES Cyber Systems and include, at a minimum, the required items appropriate to personnel roles and responsibilities from Table R2. The Responsible Entity has the flexibility to define the training program and it may consist of multiple modules and multiple delivery mechanisms, but a single training program for all individuals needing to be trained is acceptable. The training can focus on functions, roles or responsibilities at the discretion of the Responsible Entity.

One new element in the training content is intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems as per FERC Order No. 706, Paragraph 434. This is not intended to provide technical training to individuals supporting networking hardware and software, but educating system users of the cyber security risks associated with the interconnectedness of these systems. The users, based on their function, role or responsibility, should have a basic understanding of which systems can be accessed from other systems and how the actions they take can affect cyber security.

Each Responsible Entity shall ensure all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, complete cyber security training prior to their being granted authorized access, except for CIP Exceptional Circumstances. To retain the authorized accesses, individuals must complete the training at least one every 15 months.

Requirement R3:

Each Responsible Entity shall ensure a personnel risk assessment is performed for all personnel who are granted authorized electronic access and/or authorized unescorted physical access to its BES Cyber Systems, including contractors and service vendors, prior to their being granted authorized access, except for program specified exceptional circumstances that are approved by the single senior management official or their delegate and impact the reliability of the BES or emergency response. Identity should be confirmed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. Identity only needs to be confirmed prior to initially granting access and only requires periodic confirmation according to the entity's process during the tenure of employment, which may or may not be the same as the initial verification action.

A seven year criminal history check should be performed for those locations where the individual has resided for at least six consecutive months. This check should also be performed in accordance with federal, state, provincial, and local laws, and subject to existing collective bargaining unit agreements. When it is not possible to perform a full seven year criminal history check, documentation must be made of what criminal history check was performed, and the reasons a full seven-year check could not be performed. Examples of this could include

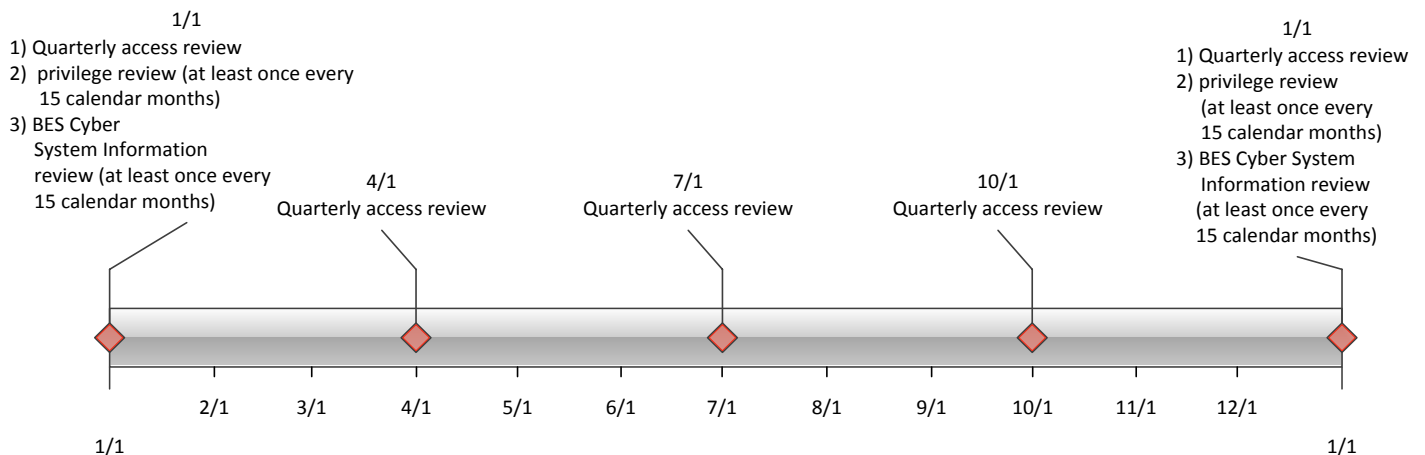
individuals under the age of 25 where a juvenile criminal history may be protected by law, individuals who may have resided in locations from where it is not possible to obtain a criminal history records check, violates the law or is not allowed under the existing collective bargaining agreement. The Responsible Entity should consider the absence of information for the full seven years when assessing the risk of granting access during the process to evaluate the criminal history check. There needs to be a personnel risk assessment that has been completed within the last seven years for each individual with access. A new criminal history records check must be performed as part of the new PRA. Individuals who have been granted access under a previous version of these standards need a new PRA within seven years of the date of their last PRA. The clarifications around the seven year criminal history check in this version do not require a new PRA be performed by the implementation date.

Requirement R4:

Authorization for electronic and unescorted physical access and access to BES Cyber System Information must be on the basis of necessity in the individual performing a work function. Documentation showing the authorization should have some justification of the business need included. To ensure proper segregation of duties, access authorization and provisioning should not be performed by the same person where possible.

This requirement specifies both quarterly reviews and reviews at least once every 15 calendar months. Quarterly reviews are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

The privilege review at least once every 15 calendar months is more detailed to ensure an individual’s associated privileges are the minimum necessary to perform their work function



(i.e., least privilege). Entities can more efficiently perform this review by implementing role-based access. This involves determining the specific roles on the system (e.g., system operator, technician, report viewer, administrator, etc.) then grouping access privileges to the role and assigning users to the role. Role-based access does not assume any specific software and can be implemented by defining specific provisioning processes for each role where access group assignments cannot be performed. Role-based access permissions eliminate the need to perform the privilege review on individual accounts. An example timeline of all the reviews in Requirement R4 is included below.

Separation of duties should be considered when performing the reviews in Requirement R4. The person reviewing should be different than the person provisioning access.

If the results of quarterly or at least once every 15 calendar months account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that this error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

Requirement R5:

The requirement to revoke access at the time of the termination action includes procedures showing revocation of access concurrent with the termination action. This requirement recognizes that the timing of the termination action may vary depending on the circumstance. Some common scenarios and possible processes on when the termination action occurs are provided in the following table. These scenarios are not an exhaustive list of all scenarios, but are representative of several routine business practices.

Scenario	Possible Process
Immediate involuntary termination	Human resources or corporate security escorts the individual off site and the supervisor or human resources personnel notify the appropriate personnel to begin the revocation process.
Scheduled involuntary termination	Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.
Voluntary termination	Human resources personnel are notified of the termination and work with appropriate personnel to schedule the revocation of access at the time of termination.
Retirement where the last working day is several weeks prior to the termination date	Human resources personnel coordinate with manager to determine the final date access is no longer needed and schedule the revocation of access on the determined day.

Death	Human resources personnel are notified of the death and work with appropriate personnel to begin the revocation process.
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Revocation of electronic access should be understood to mean a process with the end result that electronic access to BES Cyber Systems is no longer possible using credentials assigned to or known by the individual(s) whose access privileges are being revoked. Steps taken to accomplish this outcome may include deletion or deactivation of accounts used by the individual(s), but no specific actions are prescribed. Entities should consider the ramifications of deleting an account may include incomplete event log entries due to an unrecognized account or system services using the account to log on.

The initial revocation required in Requirement R5.1 includes unescorted physical access and Interactive Remote Access. These two actions should prevent any further access by the individual after termination. If an individual still has local access accounts (i.e., accounts on the Cyber Asset itself) on BES Cyber Assets, then the Responsible Entity has 30 days to complete the revocation process for those accounts. However, nothing prevents a Responsible Entity from performing all of the access revocation at the time of termination.

For transferred or reassigned individuals, a review of access privileges should be performed. This review could entail a simple listing of all authorizations for an individual and working with the respective managers to determine which access will still be needed in the new position. For instances in which the individual still needs to retain access as part of a transitory period, the entity should schedule a time to review these access privileges or include the privileges in the quarterly account review or annual privilege review.

Revocation of access to shared accounts is called out separately to prevent the situation where passwords on substation and generation devices are constantly changed due to staff turnover.

Requirement 5.5 specified that passwords for shared account are to be changed within 30 calendar days of the termination action or when the Responsible Entity determines an individual no longer requires access to the account as a result of a reassignment or transfer. The 30 days applies under normal operating conditions. However, circumstances may occur where this is not possible. Some systems may require an outage or reboot of the system in order to complete the password change. In periods of extreme heat or cold, many Responsible Entities may prohibit system outages and reboots in order to maintain reliability of the BES. When these circumstances occur, the Responsible Entity must document these circumstances and prepare to change the password within 10 calendar days following the end of the operating circumstances. Records of activities must be retained to show that the Responsible Entity followed the plan they created.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

Ensures that Responsible Entities with personnel who have authorized electronic or authorized unescorted physical access to BES Cyber Assets take action so that those personnel with such authorized electronic or authorized unescorted physical access maintain awareness of the Responsible Entity's security practices.

Summary of Changes: Reformatted into table structure.

Reference to prior version: (Part 1.1) CIP-004-4, R1

Change Rationale: (Part 1.1)

Changed to remove the need to ensure or prove everyone with authorized electronic or authorized unescorted physical access "received" ongoing reinforcement – to state that security awareness has been reinforced.

Moved example mechanisms to guidance.

Rationale for R2:

To ensure that the Responsible Entity's training program for personnel who need authorized electronic access and/or authorized unescorted physical access to BES Cyber Systems covers the proper policies, access controls, and procedures to protect BES Cyber Systems and are trained before access is authorized.

Based on their role, some personnel may not require training on all topics.

Summary of Changes:

1. Addition of specific role training for:

- The visitor control program
- Electronic interconnectivity supporting the operation and control of BES Cyber Systems
- Storage media as part of the handling of BES Cyber Systems information

2. Change references from Critical Cyber Assets to BES Cyber Systems.

Reference to prior version: (Part 2.1) CIP004-4, R2.2.1

Change Rationale: (Part 2.1)

Removed "proper use of Critical Cyber Assets" concept from previous versions to focus the requirement on cyber security issues, not the business function. The previous version was

focused more on the business or functional use of the BES Cyber System and is outside the scope of cyber security. Personnel who will administer the visitor control process or serve as escorts for visitors need training on the program. Core training on the handling of BES Cyber System (not Critical Cyber Assets) Information, with the addition of storage; FERC Order No. 706, paragraph 413 and paragraphs 632-634, 688, 732-734; DHS 2.4.16. Core training on the identification and reporting of a Cyber Security Incident; FERC Order No. 706, Paragraph 413; Related to CIP-008-5(X) & DHS Incident Reporting requirements for those with roles in incident reporting. Core training on the action plans and procedures to recover or re-establish BES Cyber Systems for personnel having a role in the recovery; FERC Order No. 706, Paragraph 413. Core training programs are intended to encompass networking hardware and software and other issues of electronic interconnectivity supporting the operation and control of BES Cyber Systems; FERC Order No. 706, Paragraph 434.

Reference to prior version: (Part 2.2) CIP004-4, R2.1

Change Rationale: (Part 2.2)

Addition of exceptional circumstances parameters as directed in FERC Order No. 706, Paragraph 431 is detailed in CIP-003-5(X).

Reference to prior version: (Part 2.3) CIP004-4, R2.3

Change Rationale: (Part 2.3)

Updated to replace “annually” with “once every 15 calendar months.”

Rationale for R3:

To ensure that individuals who need authorized electronic or authorized unescorted physical access to BES Cyber Systems have been assessed for risk. Whether initial access or maintaining access, those with access must have had a personnel risk assessment completed within the last 7 years.

Summary of Changes: Specify that the seven year criminal history check covers all locations where the individual has resided for six consecutive months or more, including current residence regardless of duration.

Reference to prior version: (Part 3.1) CIP004-4, R3.1

Change Rationale: (Part 3.1)

Addressed interpretation request in guidance. Specified that process for identity confirmation is required. The implementation plan clarifies that a documented identity verification conducted under an earlier version of the CIP standards is sufficient.

Reference to prior version: (Part 3.2) CIP004-4, R3.1

Change Rationale: (Part 3.2)

Specify that the seven year criminal history check covers all locations where the individual has resided for six months or more, including current residence regardless of duration. Added

additional wording based on interpretation request. Provision is made for when a full seven-year check cannot be performed.

Reference to prior version: (Part 3.3) New

Change Rationale: (Part 3.3)

There should be documented criteria or a process used to evaluate criminal history records checks for authorizing access.

Reference to prior version: (Part 3.4) CIP-004-4, R3.3

Change Rationale: (Part 3.4)

Separated into its own table item.

Reference to prior version: (Part 3.5) CIP-004-3, R3, R3.3

Change Rationale: (Part 3.5)

Whether for initial access or maintaining access, establishes that those with access must have had PRA completed within 7 years. This covers both initial and renewal. The implementation plan specifies that initial performance of this requirement is 7 years after the last personnel risk assessment that was performed pursuant to a previous version of the CIP Cyber Security Standards for a personnel risk assessment. CIP-004-3, R3, R3.3

Rationale for R4:

To ensure that individuals with access to BES Cyber Systems and the physical and electronic locations where BES Cyber System Information is stored by the Responsible Entity have been properly authorized for such access. "Authorization" should be considered to be a grant of permission by a person or persons empowered by the Responsible Entity to perform such grants and included in the delegations referenced in CIP-003-5(X). "Provisioning" should be considered the actions to provide access to an individual.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (i.e., physical access control system, remote access system, directory services).

CIP Exceptional Circumstances are defined in a Responsible Entity's policy from CIP-003-5(X) and allow an exception to the requirement for authorization to BES Cyber Systems and BES Cyber System Information.

Quarterly reviews in Part 4.5 are to perform a validation that only authorized users have been granted access to BES Cyber Systems. This is achieved by comparing individuals actually provisioned to a BES Cyber System against records of individuals authorized to access the BES Cyber System. The focus of this requirement is on the integrity of provisioning access rather than individual accounts on all BES Cyber Assets. The list of provisioned individuals can be an automatically generated account listing. However, in a BES Cyber System with several account

databases, the list of provisioned individuals may come from other records such as provisioning workflow or a user account database where provisioning typically initiates.

If the results of quarterly or annual account reviews indicate an administrative or clerical error in which access was not actually provisioned, then the SDT intends that the error should not be considered a violation of this requirement.

For BES Cyber Systems that do not have user accounts defined, the controls listed in Requirement R4 are not applicable. However, the Responsible Entity should document such configurations.

Summary of Changes: The primary change was in pulling the access management requirements from CIP-003-4, CIP-004-4, and CIP-007-4 into a single requirement. The requirements from Version 4 remain largely unchanged except to clarify some terminology. The purpose for combining these requirements is to remove the perceived redundancy in authorization and review. The requirement in CIP-004-4 R4 to maintain a list of authorized personnel has been removed because the list represents only one form of evidence to demonstrate compliance that only authorized persons have access.

Reference to prior version: (Part 4.1) CIP 003-4, R5.1 and R5.2; CIP-006-4, R1.5 and R4; CIP-007-4, R5.1 and R5.1.1

Change Rationale: (Part 4.1)

Combined requirements from CIP-003-4, CIP-007-4, and CIP-006-4 to make the authorization process clear and consistent. *CIP-003-4, CIP-004-4, CIP-006-4, and CIP-007-4 all reference authorization of access in some form, and CIP-003-4 and CIP-007-4 require authorization on a “need to know” basis or with respect to work functions performed. These were consolidated to ensure consistency in the requirement language.*

Reference to prior version: (Part 4.2) CIP 004-4, R4.1

Change Rationale: (Part 4.2)

Feedback among team members, observers, and regional CIP auditors indicates there has been confusion in implementation around what the term “review” entailed in CIP-004-4, Requirement R4.1. This requirement clarifies the review should occur between the provisioned access and authorized access.

Reference to prior version: (Part 4.3) CIP 007-4, R5.1.3

Change Rationale: (Part 4.3)

Moved requirements to ensure consistency and eliminate the cross-referencing of requirements. Clarified what was necessary in performing verification by stating the objective was to confirm that access privileges are correct and the minimum necessary.

Reference to prior version: (Part 4.4) CIP-003-4, R5.1.2

Change Rationale: (Part 4.4)

Moved requirement to ensure consistency among access reviews. Clarified precise meaning of annual. Clarified what was necessary in performing a verification by stating the objective was to

confirm access privileges are correct and the minimum necessary for performing assigned work functions.

Rationale for R5:

The timely revocation of electronic access to BES Cyber Systems is an essential element of an access management regime. When an individual no longer requires access to a BES Cyber System to perform his or her assigned functions, that access should be revoked. This is of particular importance in situations where a change of assignment or employment is involuntary, as there is a risk the individual(s) involved will react in a hostile or destructive manner.

In considering how to address directives in FERC Order No. 706 directing “immediate” revocation of access for involuntary separation, the SDT chose not to specify hourly time parameters in the requirement (e.g., revoking access within 1 hour). The point in time at which an organization terminates a person cannot generally be determined down to the hour. However, most organizations have formal termination processes, and the timeliest revocation of access occurs in concurrence with the initial processes of termination.

Access is physical, logical, and remote permissions granted to Cyber Assets composing the BES Cyber System or allowing access to the BES Cyber System. When granting, reviewing, or revoking access, the Responsible Entity must address the Cyber Asset specifically as well as the systems used to enable such access (e.g., physical access control system, remote access system, directory services).

Summary of Changes: FERC Order No. 706, Paragraphs 460 and 461, state the following: “The Commission adopts the CIP NOPR proposal to direct the ERO to develop modifications to CIP-004-1 to require immediate revocation of access privileges when an employee, contractor or vendor no longer performs a function that requires physical or electronic access to a Critical Cyber Asset for any reason (including disciplinary action, transfer, retirement, or termination).

As a general matter, the Commission believes that revoking access when an employee no longer needs it, either because of a change in job or the end of employment, must be immediate.”

Reference to prior version: (Part 5.1) CIP 004-4, R4.2

Change Rationale: (Part 5.1)

*The FERC Order No. 706, Paragraphs 460 and 461, directs modifications to the Standards to **require immediate revocation** for any person no longer needing access. To address this directive, this requirement specifies revocation concurrent with the termination instead of within 24 hours.*

Reference to prior version: (Part 5.2) CIP-004-4, R4.2

Change Rationale: (Part 5.2)

FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access, including transferred employees. In reviewing how to modify this requirement, the SDT determined the date a person no longer needs access after a transfer was problematic because the need may change over time. As a result, the SDT adapted this requirement from NIST 800-53 Version 3 to review access authorizations on the date of the transfer. The SDT felt this was a more effective control in accomplishing the objective to prevent a person from accumulating unnecessary authorizations through transfers.

Reference to prior version: (Part 5.3) New

Change Rationale: (Part 5.3)

FERC Order No. 706, Paragraph 386, directs modifications to the standards to require prompt revocation of access to protected information. To address this directive, Responsible Entities are required to revoke access to areas designated for BES Cyber System Information. This could include records closets, substation control houses, records management systems, file shares or other physical and logical areas under the Responsible Entity's control.

Reference to prior version: (Part 5.4) New

Change Rationale: (Part 5.4)

FERC Order No. 706, Paragraph 460 and 461, direct modifications to the Standards to require immediate revocation for any person no longer needing access. In order to meet the immediate timeframe, Responsible Entities will likely have initial revocation procedures to prevent remote and physical access to the BES Cyber System. Some cases may take more time to coordinate access revocation on individual Cyber Assets and applications without affecting reliability. This requirement provides the additional time to review and complete the revocation process. Although the initial actions already prevent further access, this step provides additional assurance in the access revocation process.

Reference to prior version: (Part 5.5) CIP-007-4, R5.2.3

Change Rationale: (Part 5.5)

To provide clarification of expected actions in managing the passwords.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Modified two VSLs in R4.	Errata
5.1	11/22/13	FERC Order issued approving CIP-004-5.1. (Order becomes effective on 2/3/14.)	
5.1	4/2/14	Address FERC Order 791 directive to modify Requirement R4 VRF and VSLs	R4-VRF and VSLs

Guidelines and Technical Basis

5.1	5/6/14	The NERC Board of Trustees adopted a revision to the VRF of Requirement 4 from Lower to Medium in CIP-004-5.1.	
<u>5.1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)
2. **Number:** CIP-005-5(X)
3. **Purpose:** To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-005-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-005-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-005-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-005-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **High Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to high impact BES Cyber Systems with Dial-up Connectivity.
- **High Impact BES Cyber Systems with External Routable Connectivity** – Only applies to high impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Medium Impact BES Cyber Systems** – Applies to each BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to medium impact BES Cyber Systems with Dial-up Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Electronic Access Points (EAP)** – Applies at Electronic Access Points associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-5(X) Table R1 – Electronic Security Perimeter*. *[Violation Risk Factor: Medium]* *[Time Horizon: Operations Planning and Same Day Operations]*.
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-5(X) Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-5(X) Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> • PCA Medium Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> • PCA 	All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP.	An example of evidence may include, but is not limited to, a list of all ESPs with all uniquely identifiable applicable Cyber Assets connected via a routable protocol within each ESP.

CIP-005-5(X) Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures
1.2	<p>High Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	All External Routable Connectivity must be through an identified Electronic Access Point (EAP).	An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified EAPs.

CIP-005-5(X) Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures
1.3	<p>Electronic Access Points for High Impact BES Cyber Systems</p> <p>Electronic Access Points for Medium Impact BES Cyber Systems</p>	<p>Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.</p>	<p>An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.</p>
1.4	<p>High Impact BES Cyber Systems with Dial-up Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>Where technically feasible, perform authentication when establishing Dial-up Connectivity with applicable Cyber Assets.</p>	<p>An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.</p>

CIP-005-5(X) Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures
1.5	Electronic Access Points for High Impact BES Cyber Systems Electronic Access Points for Medium Impact BES Cyber Systems at Control Centers	Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.	An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented.

- R2.** Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-5(X) Table R2 – Interactive Remote Access Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M2.** Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-5(X) Table R2 – Interactive Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-5(X) Table R2 – Interactive Remote Access Management			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>Utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.</p>	<p>Examples of evidence may include, but are not limited to, network diagrams or architecture documents.</p>
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>For all Interactive Remote Access sessions, utilize encryption that terminates at an Intermediate System.</p>	<p>An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.</p>

CIP-005-5(X) Table R2 – Interactive Remote Access Management			
Part	Applicable Systems	Requirements	Measures
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>Require multi-factor authentication for all Interactive Remote Access sessions.</p>	<p>An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used.</p> <p>Examples of authenticators may include, but are not limited to,</p> <ul style="list-style-type: none"> • Something the individual knows such as passwords or PINs. This does not include User ID; • Something the individual has such as tokens, digital certificates, or smart cards; or • Something the individual is such as fingerprints, iris scans, or other biometric characteristics.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning and Same Day Operations	Medium			The Responsible Entity did not have a method for detecting malicious communications for both inbound and outbound communications. (1.5)	<p>The Responsible Entity did not document one or more processes for CIP-005-5(X) Table R1 – Electronic Security Perimeter. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have all applicable Cyber Assets connected to a network via a routable protocol within a defined Electronic Security Perimeter (ESP). (1.1)</p> <p>OR</p> <p>External Routable Connectivity through the ESP was not through an identified EAP. (1.2)</p> <p>OR</p> <p>The Responsible Entity did not require inbound and</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						outbound access permissions and deny all other access by default. (1.3) OR The Responsible Entity did not perform authentication when establishing dial-up connectivity with the applicable Cyber Assets, where technically feasible. (1.4)
R2	Operations Planning and Same Day Operations	Medium	The Responsible Entity does not have documented processes for one or more of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for one of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for two of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

CIP-005-5(X), Requirement R1 requires segmenting of BES Cyber Systems from other systems of differing trust levels by requiring controlled Electronic Access Points between the different trust zones. Electronic Security Perimeters are also used as a primary defense layer for some BES Cyber Systems that may not inherently have sufficient cyber security functionality, such as devices that lack authentication capability.

All applicable BES Cyber Systems that are connected to a network via a routable protocol must have a defined Electronic Security Perimeter (ESP). Even standalone networks that have no external connectivity to other networks must have a defined ESP. The ESP defines a zone of protection around the BES Cyber System, and it also provides clarity for entities to determine what systems or Cyber Assets are in scope and what requirements they must meet. The ESP is used in:

- Defining the scope of ‘Associated Protected Cyber Assets’ that must also meet certain CIP requirements.
- Defining the boundary in which all of the Cyber Assets must meet the requirements of the highest impact BES Cyber System that is in the zone (the ‘high water mark’).

The CIP Cyber Security Standards do not require network segmentation of BES Cyber Systems by impact classification. Many different impact classifications can be mixed within an ESP. However, all of the Cyber Assets and BES Cyber Systems within the ESP must be protected at the level of the highest impact BES Cyber System present in the ESP (i.e., the “high water mark”) where the term “Protected Cyber Assets” is used. The CIP Cyber Security Standards accomplish the “high water mark” by associating all other Cyber Assets within the ESP, even other BES Cyber Systems of lesser impact, as “Protected Cyber Assets” of the highest impact system in the ESP.

For example, if an ESP contains both a high impact BES Cyber System and a low impact BES Cyber System, each Cyber Asset of the low impact BES Cyber System is an “Associated Protected Cyber Asset” of the high impact BES Cyber System and must meet all requirements with that designation in the applicability columns of the requirement tables.

If there is routable connectivity across the ESP into any Cyber Asset, then an Electronic Access Point (EAP) must control traffic into and out of the ESP. Responsible Entities should know what traffic needs to cross an EAP and document those reasons to ensure the EAPs limit the traffic to only those known communication needs. These include, but are not limited to, communications needed for normal operations, emergency operations, support, maintenance, and troubleshooting.

The EAP should control both inbound and outbound traffic. The standard added outbound traffic control, as it is a prime indicator of compromise and a first level of defense against zero day vulnerability-based attacks. If Cyber Assets within the ESP become compromised and attempt to communicate to unknown hosts outside the ESP (usually ‘command and control’ hosts on the Internet, or compromised ‘jump hosts’ within the Responsible Entity’s other networks acting as intermediaries), the EAPs should function as a first level of defense in stopping the exploit. This does not limit the Responsible Entity from controlling outbound traffic at the level of granularity that it deems appropriate, and large ranges of internal addresses may be allowed. The SDT’s intent is that the Responsible Entity knows what other Cyber Assets or ranges of addresses a BES Cyber System needs to communicate with and limits the communications to that known range. For example, most BES Cyber Systems within a Responsible Entity should not have the ability to communicate through an EAP to any network address in the world, but should probably be at least limited to the address space of the

Responsible Entity, and preferably to individual subnet ranges or individual hosts within the Responsible Entity's address space. The SDT's intent is not for Responsible Entities to document the inner workings of stateful firewalls, where connections initiated in one direction are allowed a return path. The intent is to know and document what systems can talk to what other systems or ranges of systems on the other side of the EAP, such that rogue connections can be detected and blocked.

This requirement applies only to communications for which access lists and 'deny by default' type requirements can be universally applied, which today are those that employ routable protocols. Direct serial, non-routable connections are not included as there is no perimeter or firewall type security that should be universally mandated across all entities and all serial communication situations. There is no firewall or perimeter capability for an RS232 cable run between two Cyber Assets. Without a clear 'perimeter type' security control that can be applied in practically every circumstance, such a requirement would mostly generate technical feasibility exceptions ("TFEs") rather than increased security.

As for dial-up connectivity, the Standard Drafting Team's intent of this requirement is to prevent situations where only a phone number can establish direct connectivity to the BES Cyber Asset. If a dial-up modem is implemented in such a way that it simply answers the phone and connects the line to the BES Cyber Asset with no authentication of the calling party, it is a vulnerability to the BES Cyber System. The requirement calls for some form of authentication of the calling party before completing the connection to the BES Cyber System. Some examples of acceptable methods include dial-back modems, modems that must be remotely enabled or powered up, and modems that are only powered on by onsite personnel when needed along with policy that states they are disabled after use. If the dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.

The standard adds a requirement to detect malicious communications for Control Centers. This is in response to FERC Order No. 706, Paragraphs 496-503, where ESPs are required to have two distinct security measures such that the BES Cyber Systems do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear that this is not simply redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs. Technologies meeting this requirement include Intrusion Detection or Intrusion Prevention Systems (IDS/IPS) or other forms of deep packet inspection. These technologies go beyond source/destination/port rule sets and thus provide another distinct security measure at the ESP.

Requirement R2:

See Secure Remote Access Reference Document (see remote access alert).

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The Electronic Security Perimeter (“ESP”) serves to control traffic at the external electronic boundary of the BES Cyber System. It provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

Summary of Changes: CIP-005, Requirement R1 has taken more of a focus on the discrete Electronic Access Points, rather than the logical “perimeter.”

CIP-005 (V1 through V4), Requirement R1.2 has been deleted from V5. This requirement was definitional in nature and used to bring dial-up modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists as a blanket CIP-002 filter for applicability in V5, therefore there is no need for this requirement.

CIP-005 (V1 through V4), Requirement R1.1 and R1.3 were also definitional in nature and have been deleted from V5 as separate requirements but the concepts were integrated into the definitions of ESP and Electronic Access Point (“EAP”).

Reference to prior version: (Part 1.1) CIP-005-4, R1

Change Rationale: (Part 1.1)

Explicitly clarifies that BES Cyber Assets connected via routable protocol must be in an Electronic Security Perimeter.

Reference to prior version: (Part 1.2) CIP-005-4, R1

Change Rationale: (Part 1.2)

Changed to refer to the defined term Electronic Access Point and BES Cyber System.

Reference to prior version: (Part 1.3) CIP-005-4, R2.1

Change Rationale: (Part 1.3)

Changed to refer to the defined term Electronic Access Point and to focus on the entity knowing and having a reason for what it allows through the EAP in both inbound and outbound directions.

Reference to prior version: (Part 1.4) CIP-005-4, R2.3

Change Rationale: (Part 1.4)

Added clarification that dial-up connectivity should perform authentication so that the BES Cyber System is not directly accessible with a phone number only.

Reference to prior version: (Part 1.5) CIP-005-4, R1

Change Rationale: (Part 1.5)

Per FERC Order No. 706, Paragraphs 496-503, ESPs need two distinct security measures such that the Cyber Assets do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear this is not simple redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs.

Rationale for R2:

Registered Entities use Interactive Remote Access to access Cyber Assets to support and maintain control systems networks. Discovery and announcement of vulnerabilities for remote access methods and technologies, that were previously thought secure and in use by a number of electric sector entities, necessitate changes to industry security control standards. Currently, no requirements are in effect for management of secure remote access to Cyber Assets to be afforded the NERC CIP protective measures. Inadequate safeguards for remote access can allow unauthorized access to the organization's network, with potentially serious consequences. Additional information is provided in **Guidance for Secure Interactive Remote Access** published by NERC in July 2011.

Remote access control procedures must provide adequate safeguards through robust identification, authentication and encryption techniques. Remote access to the organization's network and resources will only be permitted providing that authorized users are authenticated, data is encrypted across the network, and privileges are restricted.

The Intermediate System serves as a proxy for the remote user. Rather than allowing all the protocols the user might need to access Cyber Assets inside the Electronic Security Perimeter to traverse from the Electronic Security Perimeter to the remote computer, only the protocol required for remotely controlling the jump host is required. This allows the firewall rules to be much more restrictive than if the remote computer was allowed to connect to Cyber Assets within the Electronic Security Perimeter directly. The use of an Intermediate System also protects the Cyber Asset from vulnerabilities on the remote computer.

The use of multi-factor authentication provides an added layer of security. Passwords can be guessed, stolen, hijacked, found, or given away. They are subject to automated attacks including brute force attacks, in which possible passwords are tried until the password is found, or dictionary attacks, where words and word combinations are tested as possible passwords. But if a password or PIN must be supplied along with a one-time password supplied by a token, a fingerprint, or some other factor, the password is of no value unless the other factor(s) used for authentication are acquired along with it.

Encryption is used to protect the data that is sent between the remote computer and the Intermediate System. Data encryption is important for anyone who wants or needs secure data transfer. Encryption is needed when there is a risk of unauthorized interception of transmissions on the communications link. This is especially important when using the Internet as the communication means.

Summary of Changes: This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

Reference to prior version: (Part 2.1) New

Change Rationale: (Part 2.1)

This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

Reference to prior version: (Part 2.2) CIP-007-5(X), R3.1

Change Rationale: (Part 2.2)

This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The purpose of this part is to protect the confidentiality and integrity of each Interactive Remote Access session.

Reference to prior version: (Part 2.3) CIP-007-5(X), R3.2

Change Rationale: (Part 2.3)

This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The multi-factor authentication methods are also the same as those identified in the Homeland Security Presidential Directive 12 (HSPD-12), issued August 12, 2007.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-005-5. (Order becomes effective on 2/3/14.)	
5(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial

			Action Scheme and RAS
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A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)
2. **Number:** CIP-005-5(X)
3. **Purpose:** To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-005-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-005-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-005-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-005-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **High Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to high impact BES Cyber Systems with Dial-up Connectivity.
- **High Impact BES Cyber Systems with External Routable Connectivity** – Only applies to high impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Medium Impact BES Cyber Systems** – Applies to each BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to medium impact BES Cyber Systems with Dial-up Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Electronic Access Points (EAP)** – Applies at Electronic Access Points associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in CIP-005-5(X) Table R1 – Electronic Security Perimeter. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M1.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in CIP-005-5(X) Table R1 – Electronic Security Perimeter and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-5(X) Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> • PCA Medium Impact BES Cyber Systems and their associated: <ul style="list-style-type: none"> • PCA 	All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP.	An example of evidence may include, but is not limited to, a list of all ESPs with all uniquely identifiable applicable Cyber Assets connected via a routable protocol within each ESP.

CIP-005-5(X) Table R1 – Electronic Security Perimeter

Part	Applicable Systems	Requirements	Measures
1.2	<p>High Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>All External Routable Connectivity must be through an identified Electronic Access Point (EAP).</p>	<p>An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified EAPs.</p>

CIP-005-5(X) Table R1 – Electronic Security Perimeter

Part	Applicable Systems	Requirements	Measures
1.3	Electronic Access Points for High Impact BES Cyber Systems Electronic Access Points for Medium Impact BES Cyber Systems	Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.	An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.
1.4	High Impact BES Cyber Systems with Dial-up Connectivity and their associated: <ul style="list-style-type: none"> • PCA Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated: <ul style="list-style-type: none"> • PCA 	Where technically feasible, perform authentication when establishing Dial-up Connectivity with applicable Cyber Assets.	An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.

CIP-005-5(X) Table R1 – Electronic Security Perimeter			
Part	Applicable Systems	Requirements	Measures
1.5	<p>Electronic Access Points for High Impact BES Cyber Systems</p> <p>Electronic Access Points for Medium Impact BES Cyber Systems at Control Centers</p>	<p>Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.</p>	<p>An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented.</p>

- R2.** Each Responsible Entity allowing Interactive Remote Access to BES Cyber Systems shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-5(X) Table R2 – Interactive Remote Access Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].
- M2.** Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-5(X) Table R2 – Interactive Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-5(X) Table R2 – Interactive Remote Access Management			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>Utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.</p>	<p>Examples of evidence may include, but are not limited to, network diagrams or architecture documents.</p>
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>For all Interactive Remote Access sessions, utilize encryption that terminates at an Intermediate System.</p>	<p>An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.</p>

CIP-005-5(X) Table R2 – Interactive Remote Access Management			
Part	Applicable Systems	Requirements	Measures
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ul style="list-style-type: none"> • PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ul style="list-style-type: none"> • PCA 	<p>Require multi-factor authentication for all Interactive Remote Access sessions.</p>	<p>An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used.</p> <p>Examples of authenticators may include, but are not limited to,</p> <ul style="list-style-type: none"> • Something the individual knows such as passwords or PINs. This does not include User ID; • Something the individual has such as tokens, digital certificates, or smart cards; or • Something the individual is such as fingerprints, iris scans, or other biometric characteristics.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning and Same Day Operations	Medium			The Responsible Entity did not have a method for detecting malicious communications for both inbound and outbound communications. (1.5)	<p>The Responsible Entity did not document one or more processes for CIP-005-5(X) Table R1 – Electronic Security Perimeter. (R1)</p> <p>OR</p> <p>The Responsible Entity did not have all applicable Cyber Assets connected to a network via a routable protocol within a defined Electronic Security Perimeter (ESP). (1.1)</p> <p>OR</p> <p>External Routable Connectivity through the ESP was not through an identified EAP. (1.2)</p> <p>OR</p> <p>The Responsible Entity did not require inbound and</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						outbound access permissions and deny all other access by default. (1.3) OR The Responsible Entity did not perform authentication when establishing dial-up connectivity with the applicable Cyber Assets, where technically feasible. (1.4)
R2	Operations Planning and Same Day Operations	Medium	The Responsible Entity does not have documented processes for one or more of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for one of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for two of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

CIP-005-5(X), Requirement R1 requires segmenting of BES Cyber Systems from other systems of differing trust levels by requiring controlled Electronic Access Points between the different trust zones. Electronic Security Perimeters are also used as a primary defense layer for some BES Cyber Systems that may not inherently have sufficient cyber security functionality, such as devices that lack authentication capability.

All applicable BES Cyber Systems that are connected to a network via a routable protocol must have a defined Electronic Security Perimeter (ESP). Even standalone networks that have no external connectivity to other networks must have a defined ESP. The ESP defines a zone of protection around the BES Cyber System, and it also provides clarity for entities to determine what systems or Cyber Assets are in scope and what requirements they must meet. The ESP is used in:

- Defining the scope of ‘Associated Protected Cyber Assets’ that must also meet certain CIP requirements.
- Defining the boundary in which all of the Cyber Assets must meet the requirements of the highest impact BES Cyber System that is in the zone (the ‘high water mark’).

The CIP Cyber Security Standards do not require network segmentation of BES Cyber Systems by impact classification. Many different impact classifications can be mixed within an ESP. However, all of the Cyber Assets and BES Cyber Systems within the ESP must be protected at the level of the highest impact BES Cyber System present in the ESP (i.e., the “high water mark”) where the term “Protected Cyber Assets” is used. The CIP Cyber Security Standards accomplish the “high water mark” by associating all other Cyber Assets within the ESP, even other BES Cyber Systems of lesser impact, as “Protected Cyber Assets” of the highest impact system in the ESP.

For example, if an ESP contains both a high impact BES Cyber System and a low impact BES Cyber System, each Cyber Asset of the low impact BES Cyber System is an “Associated Protected Cyber Asset” of the high impact BES Cyber System and must meet all requirements with that designation in the applicability columns of the requirement tables.

If there is routable connectivity across the ESP into any Cyber Asset, then an Electronic Access Point (EAP) must control traffic into and out of the ESP. Responsible Entities should know what traffic needs to cross an EAP and document those reasons to ensure the EAPs limit the traffic to only those known communication needs. These include, but are not limited to, communications needed for normal operations, emergency operations, support, maintenance, and troubleshooting.

The EAP should control both inbound and outbound traffic. The standard added outbound traffic control, as it is a prime indicator of compromise and a first level of defense against zero day vulnerability-based attacks. If Cyber Assets within the ESP become compromised and attempt to communicate to unknown hosts outside the ESP (usually ‘command and control’ hosts on the Internet, or compromised ‘jump hosts’ within the Responsible Entity’s other networks acting as intermediaries), the EAPs should function as a first level of defense in stopping the exploit. This does not limit the Responsible Entity from controlling outbound traffic at the level of granularity that it deems appropriate, and large ranges of internal addresses may be allowed. The SDT’s intent is that the Responsible Entity knows what other Cyber Assets or ranges of addresses a BES Cyber System needs to communicate with and limits the communications to that known range. For example, most BES Cyber Systems within a Responsible Entity should not have the ability to communicate through an EAP to any network address in the world, but should probably be at least limited to the address space of the

Responsible Entity, and preferably to individual subnet ranges or individual hosts within the Responsible Entity's address space. The SDT's intent is not for Responsible Entities to document the inner workings of stateful firewalls, where connections initiated in one direction are allowed a return path. The intent is to know and document what systems can talk to what other systems or ranges of systems on the other side of the EAP, such that rogue connections can be detected and blocked.

This requirement applies only to communications for which access lists and 'deny by default' type requirements can be universally applied, which today are those that employ routable protocols. Direct serial, non-routable connections are not included as there is no perimeter or firewall type security that should be universally mandated across all entities and all serial communication situations. There is no firewall or perimeter capability for an RS232 cable run between two Cyber Assets. Without a clear 'perimeter type' security control that can be applied in practically every circumstance, such a requirement would mostly generate technical feasibility exceptions ("TFEs") rather than increased security.

As for dial-up connectivity, the Standard Drafting Team's intent of this requirement is to prevent situations where only a phone number can establish direct connectivity to the BES Cyber Asset. If a dial-up modem is implemented in such a way that it simply answers the phone and connects the line to the BES Cyber Asset with no authentication of the calling party, it is a vulnerability to the BES Cyber System. The requirement calls for some form of authentication of the calling party before completing the connection to the BES Cyber System. Some examples of acceptable methods include dial-back modems, modems that must be remotely enabled or powered up, and modems that are only powered on by onsite personnel when needed along with policy that states they are disabled after use. If the dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.

The standard adds a requirement to detect malicious communications for Control Centers. This is in response to FERC Order No. 706, Paragraphs 496-503, where ESPs are required to have two distinct security measures such that the BES Cyber Systems do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear that this is not simply redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs. Technologies meeting this requirement include Intrusion Detection or Intrusion Prevention Systems (IDS/IPS) or other forms of deep packet inspection. These technologies go beyond source/destination/port rule sets and thus provide another distinct security measure at the ESP.

Requirement R2:

See Secure Remote Access Reference Document (see remote access alert).

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The Electronic Security Perimeter (“ESP”) serves to control traffic at the external electronic boundary of the BES Cyber System. It provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

Summary of Changes: CIP-005, Requirement R1 has taken more of a focus on the discrete Electronic Access Points, rather than the logical “perimeter.”

CIP-005 (V1 through V4), Requirement R1.2 has been deleted from V5. This requirement was definitional in nature and used to bring dial-up modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists as a blanket CIP-002 filter for applicability in V5, therefore there is no need for this requirement.

CIP-005 (V1 through V4), Requirement R1.1 and R1.3 were also definitional in nature and have been deleted from V5 as separate requirements but the concepts were integrated into the definitions of ESP and Electronic Access Point (“EAP”).

Reference to prior version: (Part 1.1) CIP-005-4, R1

Change Rationale: (Part 1.1)

Explicitly clarifies that BES Cyber Assets connected via routable protocol must be in an Electronic Security Perimeter.

Reference to prior version: (Part 1.2) CIP-005-4, R1

Change Rationale: (Part 1.2)

Changed to refer to the defined term Electronic Access Point and BES Cyber System.

Reference to prior version: (Part 1.3) CIP-005-4, R2.1

Change Rationale: (Part 1.3)

Changed to refer to the defined term Electronic Access Point and to focus on the entity knowing and having a reason for what it allows through the EAP in both inbound and outbound directions.

Reference to prior version: (Part 1.4) CIP-005-4, R2.3

Change Rationale: (Part 1.4)

Added clarification that dial-up connectivity should perform authentication so that the BES Cyber System is not directly accessible with a phone number only.

Reference to prior version: (Part 1.5) CIP-005-4, R1

Change Rationale: (Part 1.5)

Per FERC Order No. 706, Paragraphs 496-503, ESPs need two distinct security measures such that the Cyber Assets do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear this is not simple redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs.

Rationale for R2:

Registered Entities use Interactive Remote Access to access Cyber Assets to support and maintain control systems networks. Discovery and announcement of vulnerabilities for remote access methods and technologies, that were previously thought secure and in use by a number of electric sector entities, necessitate changes to industry security control standards. Currently, no requirements are in effect for management of secure remote access to Cyber Assets to be afforded the NERC CIP protective measures. Inadequate safeguards for remote access can allow unauthorized access to the organization's network, with potentially serious consequences. Additional information is provided in **Guidance for Secure Interactive Remote Access** published by NERC in July 2011.

Remote access control procedures must provide adequate safeguards through robust identification, authentication and encryption techniques. Remote access to the organization's network and resources will only be permitted providing that authorized users are authenticated, data is encrypted across the network, and privileges are restricted.

The Intermediate System serves as a proxy for the remote user. Rather than allowing all the protocols the user might need to access Cyber Assets inside the Electronic Security Perimeter to traverse from the Electronic Security Perimeter to the remote computer, only the protocol required for remotely controlling the jump host is required. This allows the firewall rules to be much more restrictive than if the remote computer was allowed to connect to Cyber Assets within the Electronic Security Perimeter directly. The use of an Intermediate System also protects the Cyber Asset from vulnerabilities on the remote computer.

The use of multi-factor authentication provides an added layer of security. Passwords can be guessed, stolen, hijacked, found, or given away. They are subject to automated attacks including brute force attacks, in which possible passwords are tried until the password is found, or dictionary attacks, where words and word combinations are tested as possible passwords. But if a password or PIN must be supplied along with a one-time password supplied by a token, a fingerprint, or some other factor, the password is of no value unless the other factor(s) used for authentication are acquired along with it.

Encryption is used to protect the data that is sent between the remote computer and the Intermediate System. Data encryption is important for anyone who wants or needs secure data transfer. Encryption is needed when there is a risk of unauthorized interception of transmissions on the communications link. This is especially important when using the Internet as the communication means.

Summary of Changes: This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

Reference to prior version: (Part 2.1) New

Change Rationale: (Part 2.1)

This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

Reference to prior version: (Part 2.2) CIP-007-5(X), R3.1

Change Rationale: (Part 2.2)

This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The purpose of this part is to protect the confidentiality and integrity of each Interactive Remote Access session.

Reference to prior version: (Part 2.3) CIP-007-5(X), R3.2

Change Rationale: (Part 2.3)

This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The multi-factor authentication methods are also the same as those identified in the Homeland Security Presidential Directive 12 (HSPD-12), issued August 12, 2007.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-005-5. (Order becomes effective on 2/3/14.)	
<u>5(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial</u>

			<u>Action Scheme and RAS</u>
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A. Introduction

1. **Title:** Cyber Security — Physical Security of BES Cyber Systems
2. **Number:** CIP-006-5(X)
3. **Purpose:** To manage physical access to BES Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-006-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-006-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-006-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-006-5 exists as part of a suite of CIP Standards related to cyber security. CIP-002-5(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies,

assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

"Applicable Systems" Columns in Tables:

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact

and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems without External Routable Connectivity** – Only applies to medium impact BES Cyber Systems without External Routable Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Locally mounted hardware or devices at the Physical Security Perimeter** – Applies to the locally mounted hardware or devices (e.g. such as motion sensors, electronic lock control mechanisms, and badge readers) at a Physical Security Perimeter associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity, and that does not contain or store access control information or independently perform access authentication. These hardware and devices are excluded in the definition of Physical Access Control Systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning and Same Day Operations].
- M1.** Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.1	<p>Medium Impact BES Cyber Systems without External Routable Connectivity</p> <p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	Define operational or procedural controls to restrict physical access.	An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist.

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.2	<p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Utilize at least one physical access control to allow unescorted physical access into each applicable Physical Security Perimeter to only those individuals who have authorized unescorted physical access.</p>	<p>An example of evidence may include, but is not limited to, language in the physical security plan that describes each Physical Security Perimeter and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.</p>

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.3	High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	Where technically feasible, utilize two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into Physical Security Perimeters to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the Physical Security Perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-5(X) Table R1– Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p>	<p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p>

CIP-006-5(X) Table R1– Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Issue an alarm or alert in response to detected unauthorized access through a physical access point into a Physical Security Perimeter to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection.</p>	<p>An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a Physical Security Perimeter and additional evidence that the alarm or alert was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.</p>
1.6	<p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	<p>Monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control System.</p>	<p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a PACS.</p>

CIP-006-5(X) Table R1– Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.7	Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	Issue an alarm or alert in response to detected unauthorized physical access to a Physical Access Control System to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of the detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to Physical Access Control Systems and additional evidence that the alarm or alerts was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated.

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.8	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access into each Physical Security Perimeter, with information to identify the individual and date and time of entry.</p>	<p>An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of physical entry into each Physical Security Perimeter and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into Physical Security Perimeters that show the individual and the date and time of entry into Physical Security Perimeter.</p>

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.9	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Retain physical access logs of entry of individuals with authorized unescorted physical access into each Physical Security Perimeter for at least ninety calendar days.</p>	<p>An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into Physical Security Perimeters that show the date and time of entry into Physical Security Perimeter.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented visitor control programs that include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations.]
- M2.** Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-5(X) Table R2 – Visitor Control Program			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each Physical Security Perimeter, except during CIP Exceptional Circumstances.</p>	<p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as visitor logs.</p>

CIP-006-5(X) Table R2 – Visitor Control Program			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Require manual or automated logging of visitor entry into and exit from the Physical Security Perimeter that includes date and time of the initial entry and last exit, the visitor’s name, and the name of an individual point of contact responsible for the visitor, except during CIP Exceptional Circumstances.</p>	<p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as dated visitor logs that include the required information.</p>
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Retain visitor logs for at least ninety calendar days.</p>	<p>An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety calendar days.</p>

- R3.** Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program*. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].
- M3.** Evidence must include each of the documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-5(X) Table R3 – Physical Access Control System Maintenance and Testing Program			
Part	Applicable Systems	Requirement	Measures
3.1	<p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity <p>Locally mounted hardware or devices at the Physical Security Perimeter associated with:</p> <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	<p>Maintenance and testing of each Physical Access Control System and locally mounted hardware or devices at the Physical Security Perimeter at least once every 24 calendar months to ensure they function properly.</p>	<p>An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each Physical Access Control System and locally mounted hardware or devices associated with each applicable Physical Security Perimeter at least once every 24 calendar months and additional evidence to demonstrate that this testing was done, such as dated maintenance records, or other documentation showing testing and maintenance has been performed on each applicable device or system at least once every 24 calendar months.</p>

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long Term Planning Same-Day Operations	Medium	<p>The Responsible Entity has a process to log authorized physical entry into any Physical Security Perimeter with sufficient information to identify the individual and date and time of entry and identified deficiencies but did not assess or correct the deficiencies. (1.8)</p> <p>OR</p> <p>The Responsible Entity has a process to log authorized physical entry into any Physical Security</p>	<p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has</p>	<p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter and identified deficiencies but did not assess or correct the deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter but did not identify, assess, or correct deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct</p>	<p>The Responsible Entity did not document or implement operational or procedural controls to restrict physical access. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access and identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access but did not identify, assess, or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Perimeter with sufficient information to identify the individual and date and time of entry but did not identify, assess, or correct the deficiencies. (1.8) OR The Responsible Entity has a process to retain physical access logs for 90 calendar days and identified deficiencies but did not assess or correct the deficiencies. (1.9) OR The Responsible Entity has a process to retain physical access logs for 90	a process communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.7)	the deficiencies. (1.5) OR The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.5) OR The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.6) OR The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.6)	documented and implemented physical access controls, but at least one control does not exist to restrict access to Applicable Systems. (1.2) OR The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, and identified deficiencies, but did not assess or correct the deficiencies. (1.2) OR The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, but did not identify, assess, or correct the deficiencies. (1.2) OR The Responsible Entity has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar days but did not identify, assess, or correct the deficiencies. (1.9)			documented and implemented physical access controls, but at least two different controls do not exist to restrict access to Applicable Systems. (1.3) OR The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, and identified deficiencies, but did not assess or correct the deficiencies. (1.3) OR The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, but did not identify, assess, or correct

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						the deficiencies. (1.3) OR The Responsible Entity does not have a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter. (1.4) OR The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter and identified deficiencies, but did not assess or correct the deficiencies. (1.4) OR The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter, but did not identify, assess, or correct the deficiencies.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						(1.4) OR The Responsible Entity does not have a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter or to communicate such alerts within 15 minutes to identified personnel. (1.5) OR The Responsible Entity does not have a process to monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control Systems. (1.6) OR The Responsible Entity does not have a process to alert for unauthorized physical access to Physical Access Control Systems or to communicate such alerts within 15 minutes to

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identified personnel (1.7) OR The Responsible Entity does not have a process to log authorized physical entry into each Physical Security Perimeter with sufficient information to identify the individual and date and time of entry. (1.8) OR The Responsible Entity does not have a process to retain physical access logs for 90 calendar days. (1.9)
R2	Same-Day Operations	Medium	N/A	The Responsible Entity included a visitor control program that requires logging of each of the initial entry and last exit dates and times of the visitor, the visitor's name, and the point of contact and identified deficiencies but did not assess or correct the deficiencies. (2.2)	The Responsible Entity included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter, and identified deficiencies but did not assess or correct deficiencies. (2.1) OR The Responsible Entity	The Responsible Entity has failed to include or implement a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter. (2.1) OR The Responsible Entity has failed to include or implement a visitor

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>OR</p> <p>The Responsible Entity included a visitor control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact and but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days and identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days but did not identify, assess, or correct the deficiencies. (2.3)</p>	<p>included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter but did not identify, assess, or correct deficiencies. (2.1)</p>	<p>control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact. (2.2)</p> <p>OR</p> <p>The Responsible Entity failed to include or implement a visitor control program to retain visitor logs for at least ninety days. (2.3)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long Term Planning	Lower	The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 24 calendar months but did complete required testing within 25 calendar months. (3.1)	The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 25 calendar months but did complete required testing within 26 calendar months. (3.1)	The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 26 calendar months but did complete required testing within 27 calendar months. (3.1)	The Responsible Entity has not documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter. (3.1) OR The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 27 calendar months. (3.1)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

General:

While the focus is shifted from the definition and management of a completely enclosed “six-wall” boundary, it is expected in many instances this will remain a primary mechanism for controlling, alerting, and logging access to BES Cyber Systems. Taken together, these controls will effectively constitute the physical security plan to manage physical access to BES Cyber Systems.

Requirement R1:

Methods of physical access control include:

- Card Key: A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- Special Locks: These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- Security Personnel: Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.

- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access into the Physical Security Perimeter.

Methods to monitor physical access include:

- Alarm Systems: Systems that alarm to indicate interior motion or when a door, gate, or window has been opened without authorization. These alarms must provide for notification within 15 minutes to individuals responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by security personnel who are also controlling physical access.

Methods to log physical access include:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and alerting method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access.

The FERC Order No. 706, Paragraph 572, directive discussed utilizing two or more different and complementary physical access controls to provide defense in depth. It does not require two or more Physical Security Perimeters, nor does it exclude the use of layered perimeters. Use of two-factor authentication would be acceptable at the same entry points for a non-layered single perimeter. For example, a sole perimeter's controls could include either a combination of card key and pin code (something you know and something you have), or a card key and biometric scanner (something you have and something you are), or a physical key in combination with a guard-monitored remote camera and door release, where the "guard" has adequate information to authenticate the person they are observing or talking to prior to permitting access (something you have and something you are). The two-factor authentication could be implemented using a single Physical Access Control System but more than one authentication method must be utilized. For physically layered protection, a locked gate in combination with a locked control-building could be acceptable, provided no single authenticator (e.g., key or card key) would provide access through both.

Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.

Requirement R2:

The logging of visitors should capture each visit of the individual and does not need to capture each entry or exit during that visit. This is meant to allow a visitor to temporarily exit the Physical Security Perimeter to obtain something they left in their vehicle or outside the area without requiring a new log entry for each and every entry during the visit.

The SDT also determined that a point of contact should be documented who can provide additional details about the visit if questions arise in the future. The point of contact could be the escort, but there is no need to document everyone that acted as an escort for the visitor.

Requirement R3:

This includes the testing of locally mounted hardware or devices used in controlling, alerting or logging access to the Physical Security Perimeter. This includes motion sensors, electronic lock control mechanisms, and badge readers which are not deemed to be part of the Physical Access Control System but are required for the protection of the BES Cyber Systems.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

Each Responsible Entity shall ensure that physical access to all BES Cyber Systems is restricted and appropriately managed. *Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.*

Summary of Changes: The entire content of CIP-006-5(X) is intended to constitute a physical security program. This represents a change from previous versions, since there was no specific requirement to have a physical security program in previous versions of the standards, only requirements for physical security plans.

Added details to address FERC Order No. 706, Paragraph 572, directives for physical security defense in depth.

Additional guidance on physical security defense in depth provided to address the directive in FERC Order No. 706, Paragraph 575.

Reference to prior version: (Part 1.1) *CIP-006-4c, R2.1 for Physical Access Control Systems New Requirement for Medium Impact BES Cyber Systems not having External Routable Connectivity*

Change Rationale: (Part 1.1)

To allow for programmatic protection controls as a baseline (which also includes how the entity plans to protect Medium Impact BES Cyber Systems that do not have External Routable Connectivity not otherwise covered under Part 1.2, and it does not require a detailed list of individuals with access). Physical Access Control Systems do not themselves need to be protected at the same level as required in Parts 1.2 through 1.5.

Reference to prior version: (Part 1.2) CIP006-4c, R3 & R4

Change Rationale: (Part 1.2)

This requirement has been made more general to allow for alternate measures of restricting physical access. Specific examples of methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.3) CIP006-4c, R3 & R4

Change Rationale: (Part 1.3)

The specific examples that specify methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section. This requirement has been made more general to allow for alternate measures of controlling physical access.

Added to address FERC Order No. 706, Paragraph 572, related directives for physical security defense in depth.

FERC Order No. 706, Paragraph 575, directives addressed by providing the examples in the guidance document of physical security defense in depth via multi-factor authentication or layered Physical Security Perimeter(s).

Reference to prior version: (Part 1.4) CIP006-4c, R5

Change Rationale: (Part 1.4)

Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.5) CIP006-4c, R5

Change Rationale: (Part 1.5)

Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.6) CIP006-4c, R5

Change Rationale: (Part 1.6)

Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.

Reference to prior version: (Part 1.7) CIP006-4c, R5

Change Rationale: (Part 1.7)

Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.

Reference to prior version: (Part 1.8) CIP-006-4c, R6

Change Rationale: (Part 1.8)

CIP-006-4c, Requirement R6 was specific to the logging of access at identified access points. This requirement more generally requires logging of authorized physical access into the Physical Security Perimeter.

Examples of logging methods have been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.9) CIP-006-4c, R7

Change Rationale: (Part 1.9)

No change.

Rationale for R2:

To control when personnel without authorized unescorted physical access can be in any Physical Security Perimeters protecting BES Cyber Systems or Electronic Access Control or Monitoring Systems, as applicable in Table R2.

Summary of Changes: Reformatted into table structure. Originally added in Version 3 per FERC Order issued September 30, 2009.

Reference to prior version: (Part 2.1) CIP-006-4c, R1.6.2

Change Rationale: (Part 2.1)

Added the ability to not do this during CIP Exceptional Circumstances.

Reference to prior version: (Part 2.2) CIP-006-4c R1.6.1

Change Rationale: (Part 2.2)

Added the ability to not do this during CIP Exceptional Circumstances, addressed multi-entry scenarios of the same person in a day (log first entry and last exit), and name of the person who is responsible or sponsor for the visitor. There is no requirement to document the escort or handoffs between escorts.

Reference to prior version: (Part 2.3) CIP-006-4c, R7

Change Rationale: (Part 2.3)

No change

Rationale for R3:

To ensure all Physical Access Control Systems and devices continue to function properly.

Summary of Changes: Reformatted into table structure.

Added details to address FERC Order No. 706, Paragraph 581, directives to test more frequently than every three years.

Reference to prior version: (Part 3.1) CIP-006-4c, R8.1 and R8.2

Change Rationale: (Part 3.1)

Added details to address FERC Order No. 706, Paragraph 581 directives to test more frequently than every three years. The SDT determined that annual testing was too often and agreed on two years.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.

Guidelines and Technical Basis

Version	Date	Action	Change Tracking
5	11/22/13	FERC Order issued approving CIP-006-5. (Order becomes effective on 2/3/14.)	
5(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — Physical Security of BES Cyber Systems
2. **Number:** CIP-006-5(X)
3. **Purpose:** To manage physical access to BES Cyber Systems by specifying a physical security plan in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-006-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-006-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-006-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-006-5 exists as part of a suite of CIP Standards related to cyber security. CIP-002-5(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept

from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems without External Routable Connectivity** – Only applies to medium impact BES Cyber Systems without External Routable Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Locally mounted hardware or devices at the Physical Security Perimeter** – Applies to the locally mounted hardware or devices (e.g. such as motion sensors, electronic lock control mechanisms, and badge readers) at a Physical Security Perimeter associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity, and that does not contain or store access control information or independently perform access authentication. These hardware and devices are excluded in the definition of Physical Access Control Systems.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning and Same Day Operations].
- M1.** Evidence must include each of the documented physical security plans that collectively include all of the applicable requirement parts in *CIP-006-5(X) Table R1 – Physical Security Plan* and additional evidence to demonstrate implementation of the plan or plans as described in the Measures column of the table.

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.1	<p>Medium Impact BES Cyber Systems without External Routable Connectivity</p> <p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	Define operational or procedural controls to restrict physical access.	An example of evidence may include, but is not limited to, documentation that operational or procedural controls exist.

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.2	<p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Utilize at least one physical access control to allow unescorted physical access into each applicable Physical Security Perimeter to only those individuals who have authorized unescorted physical access.</p>	<p>An example of evidence may include, but is not limited to, language in the physical security plan that describes each Physical Security Perimeter and how unescorted physical access is controlled by one or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.</p>

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.3	High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	Where technically feasible, utilize two or more different physical access controls (this does not require two completely independent physical access control systems) to collectively allow unescorted physical access into Physical Security Perimeters to only those individuals who have authorized unescorted physical access.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the Physical Security Perimeters and how unescorted physical access is controlled by two or more different methods and proof that unescorted physical access is restricted to only authorized individuals, such as a list of authorized individuals accompanied by access logs.

CIP-006-5(X) Table R1– Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p>	<p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized access through a physical access point into a Physical Security Perimeter.</p>

CIP-006-5(X) Table R1– Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Issue an alarm or alert in response to detected unauthorized access through a physical access point into a Physical Security Perimeter to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of detection.</p>	<p>An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized access through a physical access control into a Physical Security Perimeter and additional evidence that the alarm or alert was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as manual or electronic alarm or alert logs, cell phone or pager logs, or other evidence that documents that the alarm or alert was generated and communicated.</p>
1.6	<p>Physical Access Control Systems (PACS) associated with:</p> <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	<p>Monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control System.</p>	<p>An example of evidence may include, but is not limited to, documentation of controls that monitor for unauthorized physical access to a PACS.</p>

CIP-006-5(X) Table R1– Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.7	Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	Issue an alarm or alert in response to detected unauthorized physical access to a Physical Access Control System to the personnel identified in the BES Cyber Security Incident response plan within 15 minutes of the detection.	An example of evidence may include, but is not limited to, language in the physical security plan that describes the issuance of an alarm or alert in response to unauthorized physical access to Physical Access Control Systems and additional evidence that the alarm or alerts was issued and communicated as identified in the BES Cyber Security Incident Response Plan, such as alarm or alert logs, cell phone or pager logs, or other evidence that the alarm or alert was generated and communicated.

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.8	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Log (through automated means or by personnel who control entry) entry of each individual with authorized unescorted physical access into each Physical Security Perimeter, with information to identify the individual and date and time of entry.</p>	<p>An example of evidence may include, but is not limited to, language in the physical security plan that describes logging and recording of physical entry into each Physical Security Perimeter and additional evidence to demonstrate that this logging has been implemented, such as logs of physical access into Physical Security Perimeters that show the individual and the date and time of entry into Physical Security Perimeter.</p>

CIP-006-5(X) Table R1 – Physical Security Plan			
Part	Applicable Systems	Requirements	Measures
1.9	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Retain physical access logs of entry of individuals with authorized unescorted physical access into each Physical Security Perimeter for at least ninety calendar days.</p>	<p>An example of evidence may include, but is not limited to, dated documentation such as logs of physical access into Physical Security Perimeters that show the date and time of entry into Physical Security Perimeter.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented visitor control programs that include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations.]
- M2.** Evidence must include one or more documented visitor control programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R2 – Visitor Control Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-5(X) Table R2 – Visitor Control Program			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Require continuous escorted access of visitors (individuals who are provided access but are not authorized for unescorted physical access) within each Physical Security Perimeter, except during CIP Exceptional Circumstances.</p>	<p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as visitor logs.</p>

CIP-006-5(X) Table R2 – Visitor Control Program			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Require manual or automated logging of visitor entry into and exit from the Physical Security Perimeter that includes date and time of the initial entry and last exit, the visitor’s name, and the name of an individual point of contact responsible for the visitor, except during CIP Exceptional Circumstances.</p>	<p>An example of evidence may include, but is not limited to, language in a visitor control program that requires continuous escorted access of visitors within Physical Security Perimeters and additional evidence to demonstrate that the process was implemented, such as dated visitor logs that include the required information.</p>
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Retain visitor logs for at least ninety calendar days.</p>	<p>An example of evidence may include, but is not limited to, documentation showing logs have been retained for at least ninety calendar days.</p>

- R3.** Each Responsible Entity shall implement one or more documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program*. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].
- M3.** Evidence must include each of the documented Physical Access Control System maintenance and testing programs that collectively include each of the applicable requirement parts in *CIP-006-5(X) Table R3 – Maintenance and Testing Program* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-006-5(X) Table R3 – Physical Access Control System Maintenance and Testing Program			
Part	Applicable Systems	Requirement	Measures
3.1	Physical Access Control Systems (PACS) associated with: <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity Locally mounted hardware or devices at the Physical Security Perimeter associated with: <ul style="list-style-type: none"> • High Impact BES Cyber Systems, or • Medium Impact BES Cyber Systems with External Routable Connectivity 	Maintenance and testing of each Physical Access Control System and locally mounted hardware or devices at the Physical Security Perimeter at least once every 24 calendar months to ensure they function properly.	An example of evidence may include, but is not limited to, a maintenance and testing program that provides for testing each Physical Access Control System and locally mounted hardware or devices associated with each applicable Physical Security Perimeter at least once every 24 calendar months and additional evidence to demonstrate that this testing was done, such as dated maintenance records, or other documentation showing testing and maintenance has been performed on each applicable device or system at least once every 24 calendar months.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long Term Planning Same-Day Operations	Medium	<p>The Responsible Entity has a process to log authorized physical entry into any Physical Security Perimeter with sufficient information to identify the individual and date and time of entry and identified deficiencies but did not assess or correct the deficiencies. (1.8)</p> <p>OR</p> <p>The Responsible Entity has a process to log authorized physical entry into any Physical Security</p>	<p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for unauthorized physical access to Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has a process communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct the deficiencies. (1.7)</p> <p>OR</p> <p>The Responsible Entity has</p>	<p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter and identified deficiencies but did not assess or correct the deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter but did not identify, assess, or correct deficiencies. (1.5)</p> <p>OR</p> <p>The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel and identified deficiencies but did not assess or correct</p>	<p>The Responsible Entity did not document or implement operational or procedural controls to restrict physical access. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access and identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity documented and implemented operational or procedural controls to restrict physical access but did not identify, assess, or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Perimeter with sufficient information to identify the individual and date and time of entry but did not identify, assess, or correct the deficiencies. (1.8) OR The Responsible Entity has a process to retain physical access logs for 90 calendar days and identified deficiencies but did not assess or correct the deficiencies. (1.9) OR The Responsible Entity has a process to retain physical access logs for 90	a process communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.7)	the deficiencies. (1.5) OR The Responsible Entity has a process to communicate alerts within 15 minutes to identified personnel but did not identify, assess, or correct the deficiencies. (1.5) OR The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems and identified deficiencies but did not assess or correct the deficiencies. (1.6) OR The Responsible Entity has a process to monitor for unauthorized physical access to a Physical Access Control Systems but did not identify, assess, or correct the deficiencies. (1.6)	documented and implemented physical access controls, but at least one control does not exist to restrict access to Applicable Systems. (1.2) OR The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, and identified deficiencies, but did not assess or correct the deficiencies. (1.2) OR The Responsible Entity has documented and implemented physical access controls, restricts access to Applicable Systems using at least one control, but did not identify, assess, or correct the deficiencies. (1.2) OR The Responsible Entity has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			calendar days but did not identify, assess, or correct the deficiencies. (1.9)			documented and implemented physical access controls, but at least two different controls do not exist to restrict access to Applicable Systems. (1.3) OR The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, and identified deficiencies, but did not assess or correct the deficiencies. (1.3) OR The Responsible Entity documented and implemented operational or procedural controls, restricts access to Applicable Systems using at least two different controls, but did not identify, assess, or correct

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						<p>the deficiencies. (1.3)</p> <p>OR</p> <p>The Responsible Entity does not have a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter. (1.4)</p> <p>OR</p> <p>The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter and identified deficiencies, but did not assess or correct the deficiencies. (1.4)</p> <p>OR</p> <p>The Responsible Entity has a process to monitor for unauthorized access through a physical access point into a Physical Security Perimeter, but did not identify, assess, or correct the deficiencies.</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						(1.4) OR The Responsible Entity does not have a process to alert for detected unauthorized access through a physical access point into a Physical security Perimeter or to communicate such alerts within 15 minutes to identified personnel. (1.5) OR The Responsible Entity does not have a process to monitor each Physical Access Control System for unauthorized physical access to a Physical Access Control Systems. (1.6) OR The Responsible Entity does not have a process to alert for unauthorized physical access to Physical Access Control Systems or to communicate such alerts within 15 minutes to

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						identified personnel (1.7) OR The Responsible Entity does not have a process to log authorized physical entry into each Physical Security Perimeter with sufficient information to identify the individual and date and time of entry. (1.8) OR The Responsible Entity does not have a process to retain physical access logs for 90 calendar days. (1.9)
R2	Same-Day Operations	Medium	N/A	The Responsible Entity included a visitor control program that requires logging of each of the initial entry and last exit dates and times of the visitor, the visitor's name, and the point of contact and identified deficiencies but did not assess or correct the deficiencies. (2.2)	The Responsible Entity included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter, and identified deficiencies but did not assess or correct deficiencies. (2.1) OR The Responsible Entity	The Responsible Entity has failed to include or implement a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter. (2.1) OR The Responsible Entity has failed to include or implement a visitor

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>OR</p> <p>The Responsible Entity included a visitor control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact and but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days and identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity included a visitor control program to retain visitor logs for at least ninety days but did not identify, assess, or correct the deficiencies. (2.3)</p>	<p>included a visitor control program that requires continuous escorted access of visitors within any Physical Security Perimeter but did not identify, assess, or correct deficiencies. (2.1)</p>	<p>control program that requires logging of the initial entry and last exit dates and times of the visitor, the visitor’s name, and the point of contact. (2.2)</p> <p>OR</p> <p>The Responsible Entity failed to include or implement a visitor control program to retain visitor logs for at least ninety days. (2.3)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-006-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Long Term Planning	Lower	The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 24 calendar months but did complete required testing within 25 calendar months. (3.1)	The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 25 calendar months but did complete required testing within 26 calendar months. (3.1)	The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 26 calendar months but did complete required testing within 27 calendar months. (3.1)	The Responsible Entity has not documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter. (3.1) OR The Responsible Entity has documented and implemented a maintenance and testing program for Physical Access Control Systems and locally mounted hardware or devices at the Physical Security Perimeter, but did not complete required testing within 27 calendar months. (3.1)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

General:

While the focus is shifted from the definition and management of a completely enclosed “six-wall” boundary, it is expected in many instances this will remain a primary mechanism for controlling, alerting, and logging access to BES Cyber Systems. Taken together, these controls will effectively constitute the physical security plan to manage physical access to BES Cyber Systems.

Requirement R1:

Methods of physical access control include:

- **Card Key:** A means of electronic access where the access rights of the card holder are predefined in a computer database. Access rights may differ from one perimeter to another.
- **Special Locks:** These include, but are not limited to, locks with “restricted key” systems, magnetic locks that can be operated remotely, and “man-trap” systems.
- **Security Personnel:** Personnel responsible for controlling physical access who may reside on-site or at a monitoring station.

- Other Authentication Devices: Biometric, keypad, token, or other equivalent devices that control physical access into the Physical Security Perimeter.

Methods to monitor physical access include:

- Alarm Systems: Systems that alarm to indicate interior motion or when a door, gate, or window has been opened without authorization. These alarms must provide for notification within 15 minutes to individuals responsible for response.
- Human Observation of Access Points: Monitoring of physical access points by security personnel who are also controlling physical access.

Methods to log physical access include:

- Computerized Logging: Electronic logs produced by the Responsible Entity's selected access control and alerting method.
- Video Recording: Electronic capture of video images of sufficient quality to determine identity.
- Manual Logging: A log book or sign-in sheet, or other record of physical access maintained by security or other personnel authorized to control and monitor physical access.

The FERC Order No. 706, Paragraph 572, directive discussed utilizing two or more different and complementary physical access controls to provide defense in depth. It does not require two or more Physical Security Perimeters, nor does it exclude the use of layered perimeters. Use of two-factor authentication would be acceptable at the same entry points for a non-layered single perimeter. For example, a sole perimeter's controls could include either a combination of card key and pin code (something you know and something you have), or a card key and biometric scanner (something you have and something you are), or a physical key in combination with a guard-monitored remote camera and door release, where the "guard" has adequate information to authenticate the person they are observing or talking to prior to permitting access (something you have and something you are). The two-factor authentication could be implemented using a single Physical Access Control System but more than one authentication method must be utilized. For physically layered protection, a locked gate in combination with a locked control-building could be acceptable, provided no single authenticator (e.g., key or card key) would provide access through both.

Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.

Requirement R2:

The logging of visitors should capture each visit of the individual and does not need to capture each entry or exit during that visit. This is meant to allow a visitor to temporarily exit the Physical Security Perimeter to obtain something they left in their vehicle or outside the area without requiring a new log entry for each and every entry during the visit.

The SDT also determined that a point of contact should be documented who can provide additional details about the visit if questions arise in the future. The point of contact could be the escort, but there is no need to document everyone that acted as an escort for the visitor.

Requirement R3:

This includes the testing of locally mounted hardware or devices used in controlling, alerting or logging access to the Physical Security Perimeter. This includes motion sensors, electronic lock control mechanisms, and badge readers which are not deemed to be part of the Physical Access Control System but are required for the protection of the BES Cyber Systems.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

Each Responsible Entity shall ensure that physical access to all BES Cyber Systems is restricted and appropriately managed. *Entities may choose for certain PACS to reside in a PSP controlling access to applicable BES Cyber Systems. For these PACS, there is no additional obligation to comply with Requirement Parts 1.1, 1.7 and 1.8 beyond what is already required for the PSP.*

Summary of Changes: The entire content of CIP-006-5(X) is intended to constitute a physical security program. This represents a change from previous versions, since there was no specific requirement to have a physical security program in previous versions of the standards, only requirements for physical security plans.

Added details to address FERC Order No. 706, Paragraph 572, directives for physical security defense in depth.

Additional guidance on physical security defense in depth provided to address the directive in FERC Order No. 706, Paragraph 575.

Reference to prior version: (Part 1.1) CIP-006-4c, R2.1 for Physical Access Control Systems
New Requirement for Medium Impact BES Cyber Systems not having External Routable Connectivity

Change Rationale: (Part 1.1)

To allow for programmatic protection controls as a baseline (which also includes how the entity plans to protect Medium Impact BES Cyber Systems that do not have External Routable Connectivity not otherwise covered under Part 1.2, and it does not require a detailed list of individuals with access). Physical Access Control Systems do not themselves need to be protected at the same level as required in Parts 1.2 through 1.5.

Reference to prior version: (Part 1.2) CIP006-4c, R3 & R4

Change Rationale: (Part 1.2)

This requirement has been made more general to allow for alternate measures of restricting physical access. Specific examples of methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.3) CIP006-4c, R3 & R4

Change Rationale: (Part 1.3)

The specific examples that specify methods a Responsible Entity can take to restricting access to BES Cyber Systems has been moved to the Guidelines and Technical Basis section. This requirement has been made more general to allow for alternate measures of controlling physical access.

Added to address FERC Order No. 706, Paragraph 572, related directives for physical security defense in depth.

FERC Order No. 706, Paragraph 575, directives addressed by providing the examples in the guidance document of physical security defense in depth via multi-factor authentication or layered Physical Security Perimeter(s).

Reference to prior version: (Part 1.4) CIP006-4c, R5

Change Rationale: (Part 1.4)

Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.5) CIP006-4c, R5

Change Rationale: (Part 1.5)

Examples of monitoring methods have been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.6) CIP006-4c, R5

Change Rationale: (Part 1.6)

Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.

Reference to prior version: (Part 1.7) CIP006-4c, R5

Change Rationale: (Part 1.7)

Addresses the prior CIP-006-4c, Requirement R5 requirement for Physical Access Control Systems.

Reference to prior version: (Part 1.8) CIP-006-4c, R6

Change Rationale: (Part 1.8)

CIP-006-4c, Requirement R6 was specific to the logging of access at identified access points. This requirement more generally requires logging of authorized physical access into the Physical Security Perimeter.

Examples of logging methods have been moved to the Guidelines and Technical Basis section.

Reference to prior version: (Part 1.9) CIP-006-4c, R7

Change Rationale: (Part 1.9)

No change.

Rationale for R2:

To control when personnel without authorized unescorted physical access can be in any Physical Security Perimeters protecting BES Cyber Systems or Electronic Access Control or Monitoring Systems, as applicable in Table R2.

Summary of Changes: Reformatted into table structure. Originally added in Version 3 per FERC Order issued September 30, 2009.

Reference to prior version: (Part 2.1) CIP-006-4c, R1.6.2

Change Rationale: (Part 2.1)

Added the ability to not do this during CIP Exceptional Circumstances.

Reference to prior version: (Part 2.2) CIP-006-4c R1.6.1

Change Rationale: (Part 2.2)

Added the ability to not do this during CIP Exceptional Circumstances, addressed multi-entry scenarios of the same person in a day (log first entry and last exit), and name of the person who is responsible or sponsor for the visitor. There is no requirement to document the escort or handoffs between escorts.

Reference to prior version: (Part 2.3) CIP-006-4c, R7

Change Rationale: (Part 2.3)

No change

Rationale for R3:

To ensure all Physical Access Control Systems and devices continue to function properly.

Summary of Changes: Reformatted into table structure.

Added details to address FERC Order No. 706, Paragraph 581, directives to test more frequently than every three years.

Reference to prior version: (Part 3.1) CIP-006-4c, R8.1 and R8.2

Change Rationale: (Part 3.1)

Added details to address FERC Order No. 706, Paragraph 581 directives to test more frequently than every three years. The SDT determined that annual testing was too often and agreed on two years.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated Version Number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.

Guidelines and Technical Basis

Version	Date	Action	Change Tracking
5	11/22/13	FERC Order issued approving CIP-006-5. (Order becomes effective on 2/3/14.)	
<u>5(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — System Security Management
2. **Number:** CIP-007-5(X)
3. **Purpose:** To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-007-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-007-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-007-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-007-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies,

assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

"Applicable Systems" Columns in Tables:

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact

and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System in the applicability column. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R1 – Ports and Services*. [*Violation Risk Factor: Medium*] [*Time Horizon: Same Day Operations.*]
- M1.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R1 – Ports and Services* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R1– Ports and Services			
Part	Applicable Systems	Requirements	Measures
1.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Documentation of the need for all enabled ports on all applicable Cyber Assets and Electronic Access Points, individually or by group. • Listings of the listening ports on the Cyber Assets, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or • Configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others.
1.2	<p>High Impact BES Cyber Systems</p> <p>Medium Impact BES Cyber Systems at Control Centers</p>	<p>Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or removable media.</p>	<p>An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either logically through system configuration or physically using a port lock or signage.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>A patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable Cyber Assets that are updateable and for which a patching source exists.</p>	<p>An example of evidence may include, but is not limited to, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual BES Cyber System or Cyber Asset basis.</p>

CIP-007-5(X) Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>At least once every 35 calendar days, evaluate security patches for applicability that have been released since the last evaluation from the source or sources identified in Part 2.1.</p>	<p>An example of evidence may include, but is not limited to, an evaluation conducted by, referenced by, or on behalf of a Responsible Entity of security-related patches released by the documented sources at least once every 35 calendar days.</p>

CIP-007-5(X) Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For applicable patches identified in Part 2.2, within 35 calendar days of the evaluation completion, take one of the following actions:</p> <ul style="list-style-type: none"> • Apply the applicable patches; or • Create a dated mitigation plan; or • Revise an existing mitigation plan. <p>Mitigation plans shall include the Responsible Entity’s planned actions to mitigate the vulnerabilities addressed by each security patch and a timeframe to complete these mitigations.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Records of the installation of the patch (e.g., exports from automated patch management tools that provide installation date, verification of BES Cyber System Component software revision, or registry exports that show software has been installed); or • A dated plan showing when and how the vulnerability will be addressed, to include documentation of the actions to be taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch and a timeframe for the completion of these mitigations.

CIP-007-5(X) Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures
2.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For each mitigation plan created or revised in Part 2.3, implement the plan within the timeframe specified in the plan, unless a revision to the plan or an extension to the timeframe specified in Part 2.3 is approved by the CIP Senior Manager or delegate.</p>	<p>An example of evidence may include, but is not limited to, records of implementation of mitigations.</p>

- R3.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations].
- M3.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R3 – Malicious Code Prevention			
Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Deploy method(s) to deter, detect, or prevent malicious code.</p>	<p>An example of evidence may include, but is not limited to, records of the Responsible Entity’s performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).</p>

CIP-007-5(X) Table R3 – Malicious Code Prevention			
Part	Applicable Systems	Requirements	Measures
3.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	Mitigate the threat of detected malicious code.	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Records of response processes for malicious code detection • Records of the performance of these processes when malicious code is detected.
3.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	For those methods identified in Part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns.	An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Assessment.]
- M4.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R4 – Security Event Monitoring			
Part	Applicable Systems	Requirements	Measures
4.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Log events at the BES Cyber System level (per BES Cyber System capability) or at the Cyber Asset level (per Cyber Asset capability) for identification of, and after-the-fact investigations of, Cyber Security Incidents that includes, as a minimum, each of the following types of events:</p> <ol style="list-style-type: none"> 4.1.1. Detected successful login attempts; 4.1.2. Detected failed access attempts and failed login attempts; 4.1.3. Detected malicious code. 	<p>Examples of evidence may include, but are not limited to, a paper or system generated listing of event types for which the BES Cyber System is capable of detecting and, for generated events, is configured to log. This listing must include the required types of events.</p>

CIP-007-5(X) Table R4 – Security Event Monitoring			
Part	Applicable Systems	Requirements	Measures
4.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Generate alerts for security events that the Responsible Entity determines necessitates an alert, that includes, as a minimum, each of the following types of events (per Cyber Asset or BES Cyber System capability):</p> <ol style="list-style-type: none"> 4.2.1. Detected malicious code from Part 4.1; and 4.2.2. Detected failure of Part 4.1 event logging. 	<p>Examples of evidence may include, but are not limited to, paper or system-generated listing of security events that the Responsible Entity determined necessitate alerts, including paper or system generated list showing how alerts are configured.</p>

CIP-007-5(X) Table R4 – Security Event Monitoring			
Part	Applicable Systems	Requirements	Measures
4.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, retain applicable event logs identified in Part 4.1 for at least the last 90 consecutive calendar days except under CIP Exceptional Circumstances.</p>	<p>Examples of evidence may include, but are not limited to, documentation of the event log retention process and paper or system generated reports showing log retention configuration set at 90 days or greater.</p>
4.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 calendar days to identify undetected Cyber Security Incidents.</p>	<p>Examples of evidence may include, but are not limited to, documentation describing the review, any findings from the review (if any), and dated documentation showing the review occurred.</p>

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R5 – System Access Controls*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Have a method(s) to enforce authentication of interactive user access, where technically feasible.</p>	<p>An example of evidence may include, but is not limited to, documentation describing how access is authenticated.</p>

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s).</p>	<p>An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the BES Cyber System.</p>

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Identify individuals who have authorized access to shared accounts.</p>	<p>An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account.</p>

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	Change known default passwords, per Cyber Asset capability	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Records of a procedure that passwords are changed when new devices are in production; or • Documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For password-only authentication for interactive user access, either technically or procedurally enforce the following password parameters:</p> <ol style="list-style-type: none"> 5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset; and 5.5.2. Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the Cyber Asset. 	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • System-generated reports or screen-shots of the system-enforced password parameters, including length and complexity; or • Attestations that include a reference to the documented procedures that were followed.

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.6	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 calendar months.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • System-generated reports or screen-shots of the system-enforced periodicity of changing passwords; or • Attestations that include a reference to the documented procedures that were followed.

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.7	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, either:</p> <ul style="list-style-type: none"> • Limit the number of unsuccessful authentication attempts; or • Generate alerts after a threshold of unsuccessful authentication attempts. 	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Documentation of the account-lockout parameters; or • Rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same Day Operations	Medium	N/A	<p>The Responsible Entity has implemented and documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media and has identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has implemented and</p>	<p>The Responsible Entity has implemented and documented processes for determining necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented and documented processes for determining</p>	<p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R1 and has identified deficiencies but did not assess or correct the deficiencies. (R1)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R1 but did not</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media but did not identify, assess, or correct the deficiencies. (1.2)	necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled but did not identify, assess, or correct the deficiencies. (1.1)	identify, assess, or correct the deficiencies. (R1)
R2	Operations Planning	Medium	The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the	The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of	The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for	The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 and has identified deficiencies but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>security patches for applicability within 35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within</p>	<p>sources, for tracking or evaluating cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of sources, for tracking, or evaluating cyber security patches for applicable Cyber Assets but did not</p>	<p>applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for applicable Cyber Assets but did not identify, assess, or correct the deficiencies. (2.1)</p> <p>OR</p>	<p>not assess or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 but did not identify, assess, or correct the deficiencies. (R2)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an</p>	<p>identify, assess, or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct</p>	<p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or</p>	<p>tracking, evaluating, or installing cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for tracking, evaluating, or installing cyber security patches for applicable Cyber Assets but did not identify, assess, or</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a</p>	<p>the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p>	<p>more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the days source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by</p>	<p>correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate and has identified deficiencies but did not assess or correct the deficiencies. (2.4)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			dated mitigation plan, or revise an existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3)	OR The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct	applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3) OR The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by	an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate but did not identify, assess, or correct the deficiencies. (2.4) OR The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan and has identified deficiencies but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				the deficiencies. (2.3) OR The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion but did not identify, assess,	applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3)	not assess or correct the deficiencies. (2.4) OR The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan but did not identify, assess, or correct the deficiencies. (2.4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				or correct the deficiencies. (2.3)		
R3	Same Day Operations	Medium		<p>The Responsible Entity has implemented one or more documented process(es), but, where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es), but,</p>	<p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected</p>	<p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R3 and has identified deficiencies but did not assess or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and did not identify, assess, or correct the deficiencies. (3.3)	malicious code and did not identify, assess, or correct the deficiencies. (3.2) OR The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and has identified deficiencies but did not assess or correct the deficiencies. (3.3) OR	R3 and did not identify, assess, or correct the deficiencies. (R3) OR The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.1) OR The Responsible Entity has implemented one or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and did not identify, assess, or correct the deficiencies. (3.3)	more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and did not identify, assess, or correct the deficiencies. (3.1)
R4	Same Day Operations and Operations Assessment	Medium	The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-	The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-	The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the	The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p>	<p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p>	<p>responsible entity) for the Applicable Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and has identified deficiencies but did not assess or correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the responsible entity) for the Applicable</p>	<p>identified deficiencies but did not assess or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and did not identify, assess, or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log events for the</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4)</p>	<p>summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4)</p>	<p>Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and did not identify, assess, or correct the deficiencies. (4.2) OR The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event</p>	<p>Applicable Systems (per device or system capability) but did not detect and log all of the required types of events described in 4.1.1 through 4.1.3 and has identified deficiencies but did not assess or correct the deficiencies. (4.1) OR The Responsible Entity has documented and implemented one or more process(es) to log events for the Applicable Systems (per device or system capability) but did not detect and log all of the required types of</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					logs for at least the last 90 consecutive days and has identified deficiencies but did not assess or correct the deficiencies. (4.3) OR The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event logs for at least the last 90 consecutive days and did not	events described in 4.1.1 through 4.1.3 and did not identify, assess, or correct the deficiencies. (4.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					identify, assess, or correct the deficiencies. (4.3) OR The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and has identified deficiencies but did not assess or correct the deficiencies. (4.4)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					OR The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and did not identify, assess, or correct the deficiencies. (4.4)	
R5	Operations Planning	Medium	The Responsible Entity has implemented one or more documented process(es) for password-only	The Responsible Entity has implemented one or more documented process(es) for password-only	The Responsible Entity has implemented one or more documented process(es) for System Access	The Responsible Entity did not implement or document one or more process(es) that included the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p>	<p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p>	<p>Controls but, did not include the identification or inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and has identified deficiencies but did not assess or correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification or</p>	<p>applicable items in CIP-007-5(X) Table R5 and has identified deficiencies but did not assess or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R5 and did not identify, assess, or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)	authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)	inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and did not identify, assess, or correct the deficiencies. (5.2) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and has identified	more documented process(es) for System Access Controls but, where technically feasible, does not have a method(s) to enforce authentication of interactive user access and has identified deficiencies but did not assess or correct the deficiencies. (5.1) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, where technically feasible, does not have a

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					deficiencies but did not assess or correct the deficiencies. (5.3) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and did not identify, assess, or correct the deficiencies. (5.3) OR The Responsible Entity has implemented one or	method(s) to enforce authentication of interactive user access and did not identify, assess, or correct the deficiencies. (5.1) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords and has identified deficiencies but did not assess or correct the deficiencies. (5.4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>more documented process(es) for password-only authentication for interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for</p>	<p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords but did not identify, assess, or correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to</p>	<p>did not technically or procedurally enforce all of the password parameters described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity did not technically or procedurally enforce all of the</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6) OR The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to	password parameters described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5) OR The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)	identified deficiencies but did not assess or correct the deficiencies. (5.6) OR The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and did not identify, assess, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						correct the deficiencies. (5.6) OR The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and has identified deficiencies but did not assess or correct the deficiencies. (5.7)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and did not identify, assess, or correct the deficiencies. (5.7)

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Requirement R1 exists to reduce the attack surface of Cyber Assets by requiring entities to disable known unnecessary ports. The SDT intends for the entity to know what network accessible (“listening”) ports and associated services are accessible on their assets and systems, whether they are needed for that Cyber Asset’s function, and disable or restrict access to all other ports.

1.1. This requirement is most often accomplished by disabling the corresponding service or program that is listening on the port or configuration settings within the Cyber Asset. It can also be accomplished through using host-based firewalls, TCP_Wrappers, or other means on the Cyber Asset to restrict access. Note that the requirement is applicable at the Cyber Asset level. The Cyber Assets are those which comprise the applicable BES Cyber Systems and their associated Cyber Assets. This control is another layer in the defense against network-based attacks, therefore the SDT intends that the control be on the device itself, or positioned inline in a non-bypassable manner. Blocking ports at the ESP border does not substitute for this device level requirement. If a device has no provision for disabling or restricting logical ports on the device (example - purpose built devices that run from firmware with no port configuration available) then those ports that are open are deemed ‘needed.’

1.2. Examples of physical I/O ports include network, serial and USB ports external to the device casing. BES Cyber Systems should exist within a Physical Security Perimeter in which

case the physical I/O ports have protection from unauthorized access, but it may still be possible for accidental use such as connecting a modem, connecting a network cable that bridges networks, or inserting a USB drive. Ports used for 'console commands' primarily means serial ports on Cyber Assets that provide an administrative interface.

The protection of these ports can be accomplished in several ways including, but not limited to:

- Disabling all unneeded physical ports within the Cyber Asset's configuration
- Prominent signage, tamper tape, or other means of conveying that the ports should not be used without proper authorization
- Physical port obstruction through removable locks

This is a 'defense in depth' type control and it is acknowledged that there are other layers of control (the PSP for one) that prevent unauthorized personnel from gaining physical access to these ports. Even with physical access, it has been pointed out there are other ways to circumvent the control. This control, with its inclusion of means such as signage, is not meant to be a preventative control against intruders. Signage is indeed a directive control, not a preventative one. However, with a defense-in-depth posture, different layers and types of controls are required throughout the standard with this providing another layer for depth in Control Center environments. Once physical access has been achieved through the other preventative and detective measures by authorized personnel, a directive control that outlines proper behavior as a last line of defense are appropriate in these highest risk areas. In essence, signage would be used to remind authorized users to "think before you plug anything into one of these systems" which is the intent. This control is not designed primarily for intruders, but for example the authorized employee who intends to plug his possibly infected smartphone into an operator console USB port to charge the battery.

Requirement R2:

The SDT's intent of Requirement R2 is to require entities to know, track, and mitigate the known software vulnerabilities associated with their BES Cyber Assets. It is not strictly an "install every security patch" requirement; the main intention is to "be aware of in a timely manner and manage all known vulnerabilities" requirement.

Patch management is required for BES Cyber Systems that are accessible remotely as well as standalone systems. Stand alone systems are vulnerable to intentional or unintentional introduction of malicious code. A sound defense-in-depth security strategy employs additional measures such as physical security, malware prevention software, and software patch management to reduce the introduction of malicious code or the exploit of known vulnerabilities.

One or multiple processes could be utilized. An overall assessment process may exist in a top tier document with lower tier documents establishing the more detailed process followed for individual systems. Lower tier documents could be used to cover BES Cyber System nuances that may occur at the system level.

2.1. The Responsible Entity is to have a patch management program that covers tracking, evaluating, and installing cyber security patches. The requirement applies to patches only,

which are fixes released to handle a specific vulnerability in a hardware or software product. The requirement covers only patches that involve cyber security fixes and does not cover patches that are purely functionality related with no cyber security impact. Tracking involves processes for notification of the availability of new cyber security patches for the Cyber Assets. Documenting the patch source in the tracking portion of the process is required to determine when the assessment timeframe clock starts. This requirement handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system. The source can take many forms. The National Vulnerability Database, Operating System vendors, or Control System vendors could all be sources to monitor for release of security related patches, hotfixes, and/or updates. A patch source is not required for Cyber Assets that have no updateable software or firmware (there is no user accessible way to update the internal software or firmware executing on the Cyber Asset), or those Cyber Assets that have no existing source of patches such as vendors that no longer exist. The identification of these sources is intended to be performed once unless software is changed or added to the Cyber Asset's baseline.

2.2. Responsible Entities are to perform an assessment of security related patches within 35 days of release from their monitored source. An assessment should consist of determination of the applicability of each patch to the entity's specific environment and systems. Applicability determination is based primarily on whether the patch applies to a specific software or hardware component that the entity does have installed in an applicable Cyber Asset. A patch that applies to a service or component that is not installed in the entity's environment is not applicable. If the patch is determined to be non-applicable, that is documented with the reasons why and the entity is compliant. If the patch is applicable, the assessment can include a determination of the risk involved, how the vulnerability can be remediated, the urgency and timeframe of the remediation, and the steps the entity has previously taken or will take. Considerable care must be taken in applying security related patches, hotfixes, and/or updates or applying compensating measures to BES Cyber System or BES Cyber Assets that are no longer supported by vendors. It is possible security patches, hotfixes, and updates may reduce the reliability of the system, and entities should take this into account when determining the type of mitigation to apply. The Responsible Entities can use the information provided in the Department of Homeland Security "Quarterly Report on Cyber Vulnerabilities of Potential Risk to Control Systems" as a source. The DHS document "Recommended Practice for Patch Management of Control Systems" provides guidance on an evaluative process. It uses severity levels determined using the Common Vulnerability Scoring System Version 2. Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.

When documenting the remediation plan measures it may not be necessary to document them on a one to one basis. The remediation plan measures may be cumulative. A measure to address a software vulnerability may involve disabling a particular service. That same service may be exploited through other software vulnerabilities. Therefore disabling the single service has addressed multiple patched vulnerabilities.

2.3. The requirement handles the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity either installs the patch or documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. There are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability. For those security related patches that are determined to be applicable, the Responsible Entity must within 35 days either install the patch, create a dated mitigation plan which will outline the actions to be taken or those that have already been taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch, or revise an existing mitigation plan. Timeframes do not have to be designated as a particular calendar day but can have event designations such as “at next scheduled outage of at least two days duration.” “Mitigation plans” in the standard refers to internal documents and are not to be confused with plans that are submitted to Regional Entities in response to violations.

2.4. The entity has been notified of, has assessed, and has developed a plan to remediate the known risk and that plan must be implemented. Remediation plans that only include steps that have been previously taken are considered implemented upon completion of the documentation. Remediation plans that have steps to be taken to remediate the vulnerability must be implemented by the timeframe the entity documented in their plan. There is no maximum timeframe in this requirement as patching and other system changes carries its own risk to the availability and integrity of the systems and may require waiting until a planned outage. In periods of high demand or threatening weather, changes to systems may be curtailed or denied due to the risk to reliability.

Requirement R3:

3.1. Due to the wide range of equipment comprising the BES Cyber Systems and the wide variety of vulnerability and capability of that equipment to malware as well as the constantly evolving threat and resultant tools and controls, it is not practical within the standard to prescribe how malware is to be addressed on each Cyber Asset. Rather, the Responsible Entity determines on a BES Cyber System basis which Cyber Assets have susceptibility to malware intrusions and documents their plans and processes for addressing those risks and provides evidence that they follow those plans and processes. There are numerous options available including traditional antivirus solutions for common operating systems, white-listing solutions, network isolation techniques, portable storage media policies, Intrusion Detection/Prevention (IDS/IPS) solutions, etc. If an entity has numerous BES Cyber Systems or Cyber Assets that are of identical architecture, they may provide one process that describes how all the like Cyber Assets are covered. If a specific Cyber Asset has no updateable software and its executing code cannot be altered, then that Cyber Asset is considered to have its own internal method of deterring malicious code.

3.2. When malicious code is detected on a Cyber Asset within the applicability of this requirement, the threat posed by that code must be mitigated. In situations where traditional antivirus products are used, they may be configured to automatically remove or quarantine the malicious code. In white-listing situations, the white-listing tool itself can mitigate the threat as

it will not allow the code to execute, however steps should still be taken to remove the malicious code from the Cyber Asset. In some instances, it may be in the best interest of reliability to not immediately remove or quarantine the malicious code, such as when availability of the system may be jeopardized by removal while operating and a rebuild of the system needs to be scheduled. In that case, monitoring may be increased and steps taken to insure the malicious code cannot communicate with other systems. In some instances the entity may be working with law enforcement or other governmental entities to closely monitor the code and track the perpetrator(s). For these reasons, there is no maximum timeframe or method prescribed for the removal of the malicious code, but the requirement is to mitigate the threat posed by the now identified malicious code.

3.3. In instances where malware detection technologies depend on signatures or patterns of known attacks, the effectiveness of these tools against evolving threats is tied to the ability to keep these signatures and patterns updated in a timely manner. The entity is to have a documented process that includes the testing and installation of signature or pattern updates. In a BES Cyber System, there may be some Cyber Assets that would benefit from the more timely installation of the updates where availability of that Cyber Asset would not jeopardize the availability of the BES Cyber System's ability to perform its function. For example, some HMI workstations where portable media is utilized may benefit from having the very latest updates at all times with minimal testing. Other Cyber Assets should have any updates thoroughly tested before implementation where the result of a 'false positive' could harm the availability of the BES Cyber System. The testing should not negatively impact the reliability of the BES. The testing should be focused on the update itself and if it will have an adverse impact on the BES Cyber System. Testing in no way implies that the entity is testing to ensure that malware is indeed detected by introducing malware into the environment. It is strictly focused on ensuring that the update does not negatively impact the BES Cyber System before those updates are placed into production.

Requirement R4:

Refer to NIST 800-92 and 800-137 for additional guidance in security event monitoring.

4.1. In a complex computing environment and faced with dynamic threats and vulnerabilities, it is not practical within the standard to enumerate all security-related events necessary to support the activities for alerting and incident response. Rather, the Responsible Entity determines which computer generated events are necessary to log, provide alerts and monitor for their particular BES Cyber System environment.

Specific security events already required in Version 4 of the CIP Standards carry forward in this version. This includes access attempts at the Electronic Access Points, if any have been identified for a BES Cyber Systems. Examples of access attempts include: (i) blocked network access attempts, (ii) successful and unsuccessful remote user access attempts, (iii) blocked network access attempts from a remote VPN, and (iv) successful network access attempts or network flow information.

User access and activity events include those events generated by Cyber Assets within the Electronic Security Perimeter that have access control capability. These types of events include:

(i) successful and unsuccessful authentication, (ii) account management, (iii) object access, and (iv) processes started and stopped.

It is not the intent of the SDT that if a device cannot log a particular event that a TFE must be generated. The SDT's intent is that if any of the items in the bulleted list (for example, user logouts) can be logged by the device then the entity must log that item. If the device does not have the capability of logging that event, the entity remains compliant.

4.2. Real-time alerting allows the cyber system to automatically communicate events of significance to designated responders. This involves configuration of a communication mechanism and log analysis rules. Alerts can be configured in the form of an email, text message, or system display and alarming. The log analysis rules can exist as part of the operating system, specific application or a centralized security event monitoring system. On one end, a real-time alert could consist of a set point on an RTU for a login failure, and on the other end, a security event monitoring system could provide multiple alerting communications options triggered on any number of complex log correlation rules.

The events triggering a real-time alert may change from day to day as system administrators and incident responders better understand the types of events that might be indications of a cyber-security incident. Configuration of alerts also must balance the need for responders to know an event occurred with the potential inundation of insignificant alerts. The following list includes examples of events a Responsible Entity should consider in configuring real-time alerts:

- Detected known or potential malware or malicious activity
- Failure of security event logging mechanisms
- Login failures for critical accounts
- Interactive login of system accounts
- Enabling of accounts
- Newly provisioned accounts
- System administration or change tasks by an unauthorized user
- Authentication attempts on certain accounts during non-business hours
- Unauthorized configuration changes
- Insertion of removable media in violation of a policy

4.3 Logs that are created under Part 4.1 are to be retained on the applicable Cyber Assets or BES Cyber Systems for at least 90 days. This is different than the evidence retention period called for in the CIP standards used to prove historical compliance. For such audit purposes, the entity should maintain evidence that shows that 90 days were kept historically. One example would be records of disposition of event logs beyond 90 days up to the evidence retention period.

4.4. Reviewing logs at least every 15 days (approximately every two weeks) can consist of analyzing a summarization or sampling of logged events. NIST SP800-92 provides a lot of guidance in periodic log analysis. If a centralized security event monitoring system is used, log analysis can be performed top-down starting with a review of trends from summary reports.

The log review can also be an extension of the exercise in identifying those events needing real-time alerts by analyzing events that are not fully understood or could possibly inundate the real-time alerting.

Requirement R5:

Account types referenced in this guidance typically include:

- Shared user account: An account used by multiple users for normal business functions by employees or contractors. Usually on a device that does not support Individual User Accounts.
- Individual user account: An account used by a single user.
- Administrative account: An account with elevated privileges for performing administrative or other specialized functions. These can be individual or shared accounts.
- System account: Accounts used to run services on a system (web, DNS, mail etc). No users have access to these accounts.
- Application account: A specific system account, with rights granted at the application level often used for access into a Database.
- Guest account: An individual user account not typically used for normal business functions by employees or contractors and not associated with a specific user. May or may not be shared by multiple users.
- Remote access account: An individual user account only used for obtaining Interactive Remote Access to the BES Cyber System.
- Generic account: A group account set up by the operating system or application to perform specific operations. This differs from a shared user account in that individual users do not receive authorization for access to this account type.

5.1 Reference the Requirement's rationale.

5.2 Where possible, default and other generic accounts provided by a vendor should be removed, renamed, or disabled prior to production use of the Cyber Asset or BES Cyber System. If this is not possible, the passwords must be changed from the default provided by the vendor. Default and other generic accounts remaining enabled must be documented. For common configurations, this documentation can be performed at a BES Cyber System or more general level.

5.3 Entities may choose to identify individuals with access to shared accounts through the access authorization and provisioning process, in which case the individual authorization records suffice to meet this Requirement Part. Alternatively, entities may choose to maintain a separate listing for shared accounts. Either form of evidence achieves the end result of maintaining control of shared accounts.

5.4. Default passwords can be commonly published in vendor documentation that is readily available to all customers using that type of equipment and possibly published online.

The requirement option to have unique password addresses cases where the Cyber Asset generates or has assigned pseudo-random default passwords at the time of production or installation. In these cases, the default password does not have to change because the system or manufacturer created it specific to the Cyber Asset.

5.5. Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Technical or procedural enforcement of password parameters are required where passwords are the only credential used to authenticate individuals. Technical enforcement of the password parameters means a Cyber Asset verifies an individually selected password meets the required parameters before allowing the account to authenticate with the selected password. Technical enforcement should be used in most cases when the authenticating Cyber Asset supports enforcing password parameters. Likewise, procedural enforcement means requiring the password parameters through procedures. Individuals choosing the passwords have the obligation of ensuring the password meets the required parameters.

Password complexity refers to the policy set by a Cyber Asset to require passwords to have one or more of the following types of characters: (1) lowercase alphabetic, (2) uppercase alphabetic, (3) numeric, and (4) non-alphanumeric or “special” characters (e.g. #, \$, @, &), in various combinations.

5.6 Technical or procedural enforcement of password change obligations are required where passwords are the only credential used to authenticate individuals. Technical enforcement of password change obligations means the Cyber Asset requires a password change after a specified timeframe prior to allowing access. In this case, the password is not required to change by the specified time as long as the Cyber Asset enforces the password change after the next successful authentication of the account. Procedural enforcement means manually changing passwords used for interactive user access after a specified timeframe.

5.7 Configuring an account lockout policy or alerting after a certain number of failed authentication attempts serves to prevent unauthorized access through an online password guessing attack. The threshold of failed authentication attempts should be set high enough to avoid false-positives from authorized users failing to authenticate. It should also be set low enough to account for online password attacks occurring over an extended period of time. This threshold may be tailored to the operating environment over time to avoid unnecessary account lockouts.

Entities should take caution when configuring account lockout to avoid locking out accounts necessary for the BES Cyber System to perform a BES reliability task. In such cases, entities should configure authentication failure alerting.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The requirement is intended to minimize the attack surface of BES Cyber Systems through disabling or limiting access to unnecessary network accessible logical ports and services and physical I/O ports.

Summary of Changes: Changed the ‘needed for normal or emergency operations’ to those ports that are needed. Physical I/O ports were added in response to a FERC order. The unneeded physical ports in Control Centers (which are the highest risk, most impactful areas) should be protected as well.

Reference to prior version: (Part 1.1) CIP-007-4, R2.1 and R2.2

Change Rationale: (Part 1.1)

The requirement focuses on the entity knowing and only allowing those ports that are necessary. The additional classification of ‘normal or emergency’ added no value and has been removed.

Reference to prior version: (Part 1.2) New

Change Rationale: (Part 1.2)

On March 18, 2010, FERC issued an order to approve NERC’s interpretation of Requirement R2 of CIP-007-2. In this order, FERC agreed the term “ports” in “ports and services” refers to logical communication (e.g. TCP/IP) ports, but they also encouraged the drafting team to address unused physical ports.

Rationale for R2:

Security patch management is a proactive way of monitoring and addressing known security vulnerabilities in software before those vulnerabilities can be exploited in a malicious manner to gain control of or render a BES Cyber Asset or BES Cyber System inoperable.

The remediation plan can be updated as necessary to maintain the reliability of the BES, including an explanation of any rescheduling of the remediation actions.

Summary of Changes: The existing wordings of CIP-007, Requirements R3, R3.1, and R3.2, were separated into individual line items to provide more granularity. The documentation of a source(s) to monitor for release of security related patches, hot fixes, and/or updates for BES Cyber System or BES Cyber Assets was added to provide context as to when the “release” date was. The current wording stated “document the assessment of security patches and security

upgrades for applicability within thirty calendar days of availability of the patches or upgrades” and there has been confusion as to what constitutes the availability date. Due to issues that may occur regarding Control System vendor license and service agreements, flexibility must be given to Responsible Entities to define what sources are being monitored for BES Cyber Assets.

Reference to prior version: (Part 2.1) CIP-007, R3

Change Rationale: (Part 2.1)

The requirement is brought forward from previous CIP versions with the addition of defining the source(s) that a Responsible Entity monitors for the release of security related patches. Documenting the source is used to determine when the assessment timeframe clock starts. This requirement also handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system.

Reference to prior version: (Part 2.2) CIP-007, R3.1

Change Rationale: (Part 2.2)

Similar to the current wording but added “from the source or sources identified in 2.1” to clarify the 35-day time frame.

Reference to prior version: (Part 2.3) CIP-007, R3.2

Change Rationale: (Part 2.3)

The requirement has been changed to handle the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. The mitigation plan may, and in many cases will, consist of installing the patch. However, there are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability.

Reference to prior version: (Part 2.4) CIP-007, R3.2

Change Rationale: (Part 2.4)

Similar to the current wording but added that the plan must be implemented within the timeframe specified in the plan, or in a revised plan as approved by the CIP Senior Manager or delegate.

Rationale for R3:

Malicious code prevention has the purpose of limiting and detecting the addition of malicious code onto the applicable Cyber Assets of a BES Cyber System. Malicious code (viruses, worms, botnets, targeted code such as Stuxnet, etc.) may compromise the availability or integrity of the BES Cyber System.

Summary of Changes: In prior versions, this requirement has arguably been the single greatest generator of TFEs as it prescribed a particular technology to be used on every CCA regardless of

that asset's susceptibility or capability to use that technology. As the scope of Cyber Assets in scope of these standards expands to more field assets, this issue will grow exponentially. The drafting team is taking the approach of making this requirement a competency based requirement where the entity must document how the malware risk is handled for each BES Cyber System, but it does not prescribe a particular technical method nor does it prescribe that it must be used on every Cyber Asset. The BES Cyber System is the object of protection.

Beginning in Paragraphs 619-622 of FERC Order No. 706, and in particular Paragraph 621, FERC agrees that the standard "does not need to prescribe a single method...However, how a responsible entity does this should be detailed in its cyber security policy so that it can be audited for compliance..."

In Paragraph 622, FERC directs that the requirement be modified to include safeguards against personnel introducing, either maliciously or unintentionally, viruses or malicious software through remote access, electronic media, or other means. The drafting team believes that addressing this issue holistically at the BES Cyber System level and regardless of technology, along with the enhanced change management requirements, meets this directive.

Reference to prior version: (Part 3.1) CIP-007-4, R4; CIP-007-4, R4.1

Change Rationale: (Part 3.1)

See the Summary of Changes. FERC Order No. 706, Paragraph 621, states the standards development process should decide to what degree to protect BES Cyber Systems from personnel introducing malicious software.

Reference to prior version: (Part 3.2) CIP-007-4, R4; CIP-007-4, R4.1

Change Rationale: (Part 3.2)

See the Summary of Changes.

Reference to prior version: (Part 3.3) CIP-007-4, R4; CIP-007-4, R4.2

Change Rationale: (Part 3.3)

Requirement essentially unchanged from previous versions; updated to refer to previous parts of the requirement table.

Rationale for R4:

Rationale for R4: Security event monitoring has the purpose of detecting unauthorized access, reconnaissance and other malicious activity on BES Cyber Systems, and comprises of the activities involved with the collection, processing, alerting and retention of security-related computer logs. These logs can provide both (1) the detection of an incident and (2) useful evidence in the investigation of an incident. The retention of security-related logs is intended to support post-event data analysis.

Audit processing failures are not penalized in this requirement. Instead, the requirement specifies processes which must be in place to monitor for and notify personnel of audit processing failures.

Summary of Changes: Beginning in Paragraph 525 and also Paragraph 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis. This requirement combines CIP-005-4, R5 and CIP-007-4, R6 and addresses both directives from a system-wide perspective. The primary feedback received on this requirement from the informal comment period was the vagueness of terms “security event” and “monitor.”

The term “security event” or “events related to cyber security” is problematic because it does not apply consistently across all platforms and applications. To resolve this term, the requirement takes an approach similar to NIST 800-53 and requires the entity to define the security events relevant to the System. There are a few events explicitly listed that if a Cyber Asset or BES Cyber System can log, then it must log.

In addition, this requirement sets up parameters for the monitoring and reviewing of processes. It is rarely feasible or productive to look at every security log on the system. Paragraph 629 of the FERC Order No. 706 acknowledges this reality when directing a manual log review. As a result, this requirement allows the manual review to consist of a sampling or summarization of security events occurring since the last review.

Reference to prior version: (Part 4.1) CIP-005-4, R3; CIP-007-4, R5, R5.1.2, R6.1, and R6.3

Change Rationale: (Part 4.1)

This requirement is derived from NIST 800-53 version 3 AU-2, which requires organizations to determine system events to audit for incident response purposes. The industry expressed confusion in the term “system events related to cyber security” from informal comments received on CIP-011. Access logs from the ESP as required in CIP-005-4 Requirement R3 and user access and activity logs as required in CIP-007-5 Requirement R5 are also included here.

Reference to prior version: (Part 4.2) CIP-005-4, R3.2; CIP-007-4, R6.2

Change Rationale: (Part 4.2)

This requirement is derived from alerting requirements in CIP-005-4, Requirement R3.2 and CIP-007-4, Requirement R6.2 in addition to NIST 800-53 version 3 AU-6. Previous CIP Standards required alerting on unauthorized access attempts and detected Cyber Security Incidents, which can be vast and difficult to determine from day to day. Changes to this requirement allow the entity to determine events that necessitate a response.

Reference to prior version: (Part 4.3) CIP-005-4, R3.2; CIP-007-4, R6.4

Change Rationale: (Part 4.3)

No substantive change.

Reference to prior version: (Part 4.4) CIP-005-4, R3.2; CIP-007-4, R6.5

Change Rationale: (Part 4.4)

Beginning in Paragraph 525 and also 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis and suggests a weekly review. The Order acknowledges it is rarely feasible to review all system logs. Indeed, log review is a dynamic process that should improve over time and with additional threat information.

Changes to this requirement allow for an approximately biweekly summary or sampling review of logs.

Rationale for R5:

To help ensure that no authorized individual can gain electronic access to a BES Cyber System until the individual has been authenticated, i.e., until the individual's logon credentials have been validated. Requirement R5 also seeks to reduce the risk that static passwords, where used as authenticators, may be compromised.

Requirement Part 5.1 ensures the BES Cyber System or Cyber Asset authenticates individuals that can modify configuration information. This requirement addresses the configuration of authentication. The authorization of individuals is addressed elsewhere in the CIP Cyber Security Standards. Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Requirement Part 5.2 addresses default and other generic account types. Identifying the use of default or generic account types that could introduce vulnerabilities has the benefit ensuring entities understand the possible risk these accounts pose to the BES Cyber System. The Requirement Part avoids prescribing an action to address these accounts because the most effective solution is situation specific, and in some cases, removing or disabling the account could have reliability consequences.

Requirement Part 5.3 addresses identification of individuals with access to shared accounts. This Requirement Part has the objective of mitigating the risk of unauthorized access through shared accounts. This differs from other CIP Cyber Security Standards Requirements to authorize access. An entity can authorize access and still not know who has access to a shared account. Failure to identify individuals with access to shared accounts would make it difficult to revoke access when it is no longer needed. The term "authorized" is used in the requirement to make clear that individuals storing, losing, or inappropriately sharing a password is not a violation of this requirement.

Requirement 5.4 addresses default passwords. Changing default passwords closes an easily exploitable vulnerability in many systems and applications. Pseudo-randomly system generated passwords are not considered default passwords.

For password-based user authentication, using strong passwords and changing them periodically helps mitigate the risk of successful password cracking attacks and the risk of accidental password disclosure to unauthorized individuals. In these requirements, the drafting team considered multiple approaches to ensuring this requirement was both effective and flexible enough to allow Responsible Entities to make good security decisions. One of the approaches considered involved requiring minimum password entropy, but the calculation for

true information entropy is more highly complex and makes several assumptions in the passwords users choose. Users can pick poor passwords well below the calculated minimum entropy.

The drafting team also chose to not require technical feasibility exceptions for devices that cannot meet the length and complexity requirements in password parameters. The objective of this requirement is to apply a measurable password policy to deter password cracking attempts, and replacing devices to achieve a specified password policy does not meet this objective. At the same time, this requirement has been strengthened to require account lockout or alerting for failed login attempts, which in many instances better meets the requirement objective.

The requirement to change passwords exists to address password cracking attempts if an encrypted password were somehow attained and also to refresh passwords which may have been accidentally disclosed over time. The requirement permits the entity to specify the periodicity of change to accomplish this objective. Specifically, the drafting team felt determining the appropriate periodicity based on a number of factors is more effective than specifying the period for every BES Cyber System in the Standard. In general, passwords for user authentication should be changed at least annually. The periodicity may increase in some cases. For example, application passwords that are long and pseudo-randomly generated could have a very long periodicity. Also, passwords used only as a weak form of application authentication, such as accessing the configuration of a relay may only need to be changed as part of regularly scheduled maintenance.

The Cyber Asset should automatically enforce the password policy for individual user accounts. However, for shared accounts in which no mechanism exists to enforce password policies, the Responsible Entity can enforce the password policy procedurally and through internal assessment and audit.

Requirement Part 5.7 assists in preventing online password attacks by limiting the number of guesses an attacker can make. This requirement allows either limiting the number of failed authentication attempts or alerting after a defined number of failed authentication attempts. Entities should take caution in choosing to limit the number of failed authentication attempts for all accounts because this would allow the possibility for a denial of service attack on the BES Cyber System.

Summary of Changes (From R5):

CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. For example, many have interpreted the password for tokens or biometrics must satisfy this policy and in some cases prevents the use of this stronger authentication. Also, longer passwords may preclude the use of strict complexity requirements. The password requirements have been changed to allow the entity to specify the most effective password parameters based on the impact of the BES Cyber System, the way passwords are used, and the significance of passwords in restricting access to the system. The SDT believes these changes strengthen the authentication

mechanism by requiring entities to look at the most effective use of passwords in their environment. Otherwise, prescribing a strict password policy has the potential to limit the effectiveness of security mechanisms and preclude better mechanisms in the future.

Reference to prior version: (Part 5.1) CIP-007-4, R5

Change Rationale: (Part 5.1)

The requirement to enforce authentication for all user access is included here. The requirement to establish, implement, and document controls is included in this introductory requirement. The requirement to have technical and procedural controls was removed because technical controls suffice when procedural documentation is already required. The phrase “that minimize the risk of unauthorized access” was removed and more appropriately captured in the rationale statement.

Reference to prior version: (Part 5.2) CIP-007-4, R5.2 and R5.2.1

Change Rationale: (Part 5.2)

CIP-007-4 requires entities to minimize and manage the scope and acceptable use of account privileges. The requirement to minimize account privileges has been removed because the implementation of such a policy is difficult to measure at best.

Reference to prior version: (Part 5.3) CIP-007-4, R5.2.2

Change Rationale: (Part 5.3)

No significant changes. Added “authorized” access to make clear that individuals storing, losing or inappropriately sharing a password is not a violation of this requirement.

Reference to prior version: (Part 5.4) CIP-007-4, R5.2.1

Change Rationale: (Part 5.4)

The requirement for the “removal, disabling or renaming of such accounts where possible” has been removed and incorporated into guidance for acceptable use of account types. This was removed because those actions are not appropriate on all account types. Added the option of having unique default passwords to permit cases where a system may have generated a default password or a hard-coded uniquely generated default password was manufactured with the BES Cyber System.

Reference to prior version: (Part 5.5) CIP-007-4, R5.3

Change Rationale: (Part 5.5)

CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. The password requirements have been changed to permit the maximum allowed by the device in cases where the password parameters could otherwise not achieve a stricter policy. This change still achieves the requirement objective to minimize the risk of unauthorized disclosure of password

credentials while recognizing password parameters alone do not achieve this. The drafting team felt allowing the Responsible Entity the flexibility of applying the strictest password policy allowed by a device outweighed the need to track a relatively minimally effective control through the TFE process.

Reference to prior version: (Part 5.6) CIP-007-4, R5.3.3

Change Rationale: (Part 5.6)

**This was originally Requirement R5.5.3, but moved to add “external routable connectivity” to medium impact in response to comments. This requirement is limited in scope because the risk to performing an online password attack is lessened by its lack of external routable connectivity. Frequently changing passwords at field assets can entail significant effort with minimal risk reduction.*

Reference to prior version: (Part 5.7) New Requirement

Change Rationale: (Part 5.7)

Minimizing the number of unsuccessful login attempts significantly reduces the risk of live password cracking attempts. This is a more effective control in live password attacks than password parameters.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	

Guidelines and Technical Basis

3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-007-5. (Order becomes effective on 2/3/14.)	
5(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — System Security Management
2. **Number:** CIP-007-5(X)
3. **Purpose:** To manage system security by specifying select technical, operational, and procedural requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-007-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-007-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-007-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-007-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept

from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System in the applicability column. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R1 – Ports and Services*. [*Violation Risk Factor: Medium*] [*Time Horizon: Same Day Operations.*]
- M1.** Evidence must include the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R1 – Ports and Services* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R1– Ports and Services			
Part	Applicable Systems	Requirements	Measures
1.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, enable only logical network accessible ports that have been determined to be needed by the Responsible Entity, including port ranges or services where needed to handle dynamic ports. If a device has no provision for disabling or restricting logical ports on the device then those ports that are open are deemed needed.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Documentation of the need for all enabled ports on all applicable Cyber Assets and Electronic Access Points, individually or by group. • Listings of the listening ports on the Cyber Assets, individually or by group, from either the device configuration files, command output (such as netstat), or network scans of open ports; or • Configuration files of host-based firewalls or other device level mechanisms that only allow needed ports and deny all others.
1.2	<p>High Impact BES Cyber Systems</p> <p>Medium Impact BES Cyber Systems at Control Centers</p>	<p>Protect against the use of unnecessary physical input/output ports used for network connectivity, console commands, or removable media.</p>	<p>An example of evidence may include, but is not limited to, documentation showing types of protection of physical input/output ports, either logically through system configuration or physically using a port lock or signage.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R2 – Security Patch Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R2 – Security Patch Management

Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>A patch management process for tracking, evaluating, and installing cyber security patches for applicable Cyber Assets. The tracking portion shall include the identification of a source or sources that the Responsible Entity tracks for the release of cyber security patches for applicable Cyber Assets that are updateable and for which a patching source exists.</p>	<p>An example of evidence may include, but is not limited to, documentation of a patch management process and documentation or lists of sources that are monitored, whether on an individual BES Cyber System or Cyber Asset basis.</p>

CIP-007-5(X) Table R2 – Security Patch Management

Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>At least once every 35 calendar days, evaluate security patches for applicability that have been released since the last evaluation from the source or sources identified in Part 2.1.</p>	<p>An example of evidence may include, but is not limited to, an evaluation conducted by, referenced by, or on behalf of a Responsible Entity of security-related patches released by the documented sources at least once every 35 calendar days.</p>

CIP-007-5(X) Table R2 – Security Patch Management

Part	Applicable Systems	Requirements	Measures
2.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For applicable patches identified in Part 2.2, within 35 calendar days of the evaluation completion, take one of the following actions:</p> <ul style="list-style-type: none"> • Apply the applicable patches; or • Create a dated mitigation plan; or • Revise an existing mitigation plan. <p>Mitigation plans shall include the Responsible Entity’s planned actions to mitigate the vulnerabilities addressed by each security patch and a timeframe to complete these mitigations.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Records of the installation of the patch (e.g., exports from automated patch management tools that provide installation date, verification of BES Cyber System Component software revision, or registry exports that show software has been installed); or • A dated plan showing when and how the vulnerability will be addressed, to include documentation of the actions to be taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch and a timeframe for the completion of these mitigations.

CIP-007-5(X) Table R2 – Security Patch Management			
Part	Applicable Systems	Requirements	Measures
2.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For each mitigation plan created or revised in Part 2.3, implement the plan within the timeframe specified in the plan, unless a revision to the plan or an extension to the timeframe specified in Part 2.3 is approved by the CIP Senior Manager or delegate.</p>	<p>An example of evidence may include, but is not limited to, records of implementation of mitigations.</p>

R3. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations].

M3. Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R3 – Malicious Code Prevention* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R3 – Malicious Code Prevention

Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Deploy method(s) to deter, detect, or prevent malicious code.</p>	<p>An example of evidence may include, but is not limited to, records of the Responsible Entity’s performance of these processes (e.g., through traditional antivirus, system hardening, policies, etc.).</p>

CIP-007-5(X) Table R3 – Malicious Code Prevention			
Part	Applicable Systems	Requirements	Measures
3.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	Mitigate the threat of detected malicious code.	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Records of response processes for malicious code detection • Records of the performance of these processes when malicious code is detected.
3.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	For those methods identified in Part 3.1 that use signatures or patterns, have a process for the update of the signatures or patterns. The process must address testing and installing the signatures or patterns.	An example of evidence may include, but is not limited to, documentation showing the process used for the update of signatures or patterns.

- R4.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Same Day Operations and Operations Assessment.]
- M4.** Evidence must include each of the documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R4 – Security Event Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R4 – Security Event Monitoring			
Part	Applicable Systems	Requirements	Measures
4.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Log events at the BES Cyber System level (per BES Cyber System capability) or at the Cyber Asset level (per Cyber Asset capability) for identification of, and after-the-fact investigations of, Cyber Security Incidents that includes, as a minimum, each of the following types of events:</p> <ol style="list-style-type: none"> 4.1.1. Detected successful login attempts; 4.1.2. Detected failed access attempts and failed login attempts; 4.1.3. Detected malicious code. 	<p>Examples of evidence may include, but are not limited to, a paper or system generated listing of event types for which the BES Cyber System is capable of detecting and, for generated events, is configured to log. This listing must include the required types of events.</p>

CIP-007-5(X) Table R4 – Security Event Monitoring

Part	Applicable Systems	Requirements	Measures
4.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Generate alerts for security events that the Responsible Entity determines necessitates an alert, that includes, as a minimum, each of the following types of events (per Cyber Asset or BES Cyber System capability):</p> <ol style="list-style-type: none"> 4.2.1. Detected malicious code from Part 4.1; and 4.2.2. Detected failure of Part 4.1 event logging. 	<p>Examples of evidence may include, but are not limited to, paper or system-generated listing of security events that the Responsible Entity determined necessitate alerts, including paper or system generated list showing how alerts are configured.</p>

CIP-007-5(X) Table R4 – Security Event Monitoring			
Part	Applicable Systems	Requirements	Measures
4.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, retain applicable event logs identified in Part 4.1 for at least the last 90 consecutive calendar days except under CIP Exceptional Circumstances.</p>	<p>Examples of evidence may include, but are not limited to, documentation of the event log retention process and paper or system generated reports showing log retention configuration set at 90 days or greater.</p>
4.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	<p>Review a summarization or sampling of logged events as determined by the Responsible Entity at intervals no greater than 15 calendar days to identify undetected Cyber Security Incidents.</p>	<p>Examples of evidence may include, but are not limited to, documentation describing the review, any findings from the review (if any), and dated documentation showing the review occurred.</p>

- R5.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table R5 – System Access Controls*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].
- M5.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-007-5(X) Table 5 – System Access Controls* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-007-5(X) Table R5 – System Access Control

Part	Applicable Systems	Requirements	Measures
5.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Have a method(s) to enforce authentication of interactive user access, where technically feasible.</p>	<p>An example of evidence may include, but is not limited to, documentation describing how access is authenticated.</p>

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Identify and inventory all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s).</p>	<p>An example of evidence may include, but is not limited to, a listing of accounts by account types showing the enabled or generic account types in use for the BES Cyber System.</p>

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	Identify individuals who have authorized access to shared accounts.	An example of evidence may include, but is not limited to, listing of shared accounts and the individuals who have authorized access to each shared account.

CIP-007-5(X) Table R5 – System Access Control

Part	Applicable Systems	Requirements	Measures
5.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Change known default passwords, per Cyber Asset capability</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Records of a procedure that passwords are changed when new devices are in production; or • Documentation in system manuals or other vendor documents showing default vendor passwords were generated pseudo-randomly and are thereby unique to the device.

CIP-007-5(X) Table R5 – System Access Control

Part	Applicable Systems	Requirements	Measures
5.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For password-only authentication for interactive user access, either technically or procedurally enforce the following password parameters:</p> <ol style="list-style-type: none"> 5.5.1. Password length that is, at least, the lesser of eight characters or the maximum length supported by the Cyber Asset; and 5.5.2. Minimum password complexity that is the lesser of three or more different types of characters (e.g., uppercase alphabetic, lowercase alphabetic, numeric, non-alphanumeric) or the maximum complexity supported by the Cyber Asset. 	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • System-generated reports or screen-shots of the system-enforced password parameters, including length and complexity; or • Attestations that include a reference to the documented procedures that were followed.

CIP-007-5(X) Table R5 – System Access Control

Part	Applicable Systems	Requirements	Measures
5.6	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems with External Routable Connectivity and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, for password-only authentication for interactive user access, either technically or procedurally enforce password changes or an obligation to change the password at least once every 15 calendar months.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • System-generated reports or screen-shots of the system-enforced periodicity of changing passwords; or • Attestations that include a reference to the documented procedures that were followed.

CIP-007-5(X) Table R5 – System Access Control			
Part	Applicable Systems	Requirements	Measures
5.7	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Where technically feasible, either:</p> <ul style="list-style-type: none"> • Limit the number of unsuccessful authentication attempts; or • Generate alerts after a threshold of unsuccessful authentication attempts. 	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • Documentation of the account-lockout parameters; or • Rules in the alerting configuration showing how the system notified individuals after a determined number of unsuccessful login attempts.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Same Day Operations	Medium	N/A	<p>The Responsible Entity has implemented and documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media and has identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has implemented and</p>	<p>The Responsible Entity has implemented and documented processes for determining necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented and documented processes for determining</p>	<p>The Responsible Entity has implemented and documented processes for determining necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled and has identified deficiencies but did not assess or correct the deficiencies. (R1)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R1 but did not</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				documented processes for Ports and Services but had no methods to protect against unnecessary physical input/output ports used for network connectivity, console commands, or removable media but did not identify, assess, or correct the deficiencies. (1.2)	necessary Ports and Services but, where technically feasible, had one or more unneeded logical network accessible ports enabled but did not identify, assess, or correct the deficiencies. (1.1)	identify, assess, or correct the deficiencies. (R1)
R2	Operations Planning	Medium	The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the	The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of	The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for	The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 and has identified deficiencies but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			security patches for applicability within 35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2) OR The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within	sources, for tracking or evaluating cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1) OR The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes, including the identification of sources, for tracking, or evaluating cyber security patches for applicable Cyber Assets but did not	applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1) OR The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for installing cyber security patches for applicable Cyber Assets but did not identify, assess, or correct the deficiencies. (2.1) OR	not assess or correct the deficiencies. (R2) OR The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R2 but did not identify, assess, or correct the deficiencies. (R2) OR The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>35 calendar days but less than 50 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an</p>	<p>identify, assess, or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct</p>	<p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the source or sources identified and has identified deficiencies but did not assess or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or</p>	<p>tracking, evaluating, or installing cyber security patches for applicable Cyber Assets and has identified deficiencies but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has documented or implemented one or more process(es) for patch management but did not include any processes for tracking, evaluating, or installing cyber security patches for applicable Cyber Assets but did not identify, assess, or</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a</p>	<p>the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 50 calendar days but less than 65 calendar days of the last evaluation for the source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p>	<p>more process(es) to evaluate uninstalled released security patches for applicability but did not evaluate the security patches for applicability within 65 calendar days of the last evaluation for the days source or sources identified but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by</p>	<p>correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate and has identified deficiencies but did not assess or correct the deficiencies. (2.4)</p> <p>OR</p> <p>The Responsible Entity documented a mitigation plan for</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			dated mitigation plan, or revise an existing mitigation plan within 35 calendar days but less than 50 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3)	OR The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct	applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion and has identified deficiencies but did not assess or correct the deficiencies. (2.3) OR The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by	an applicable cyber security patch and documented a revision or extension to the timeframe but did not obtain approval by the CIP Senior Manager or delegate but did not identify, assess, or correct the deficiencies. (2.4) OR The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan and has identified deficiencies but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				the deficiencies. (2.3) OR The Responsible Entity has one or more documented process(es) for evaluating cyber security patches but, in order to mitigate the vulnerabilities exposed by applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 50 calendar days but less than 65 calendar days of the evaluation completion but did not identify, assess,	applicable security patches, did not apply the applicable patches, create a dated mitigation plan, or revise an existing mitigation plan within 65 calendar days of the evaluation completion but did not identify, assess, or correct the deficiencies. (2.3)	not assess or correct the deficiencies. (2.4) OR The Responsible Entity documented a mitigation plan for an applicable cyber security patch but did not implement the plan as created or revised within the timeframe specified in the plan but did not identify, assess, or correct the deficiencies. (2.4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				or correct the deficiencies. (2.3)		
R3	Same Day Operations	Medium		<p>The Responsible Entity has implemented one or more documented process(es), but, where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es), but,</p>	<p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not mitigate the threat of detected</p>	<p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R3 and has identified deficiencies but did not assess or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>where signatures or patterns are used, the Responsible Entity did not address testing the signatures or patterns and did not identify, assess, or correct the deficiencies. (3.3)</p>	<p>malicious code and did not identify, assess, or correct the deficiencies. (3.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and has identified deficiencies but did not assess or correct the deficiencies. (3.3)</p> <p>OR</p>	<p>R3 and did not identify, assess, or correct the deficiencies. (R3)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and has identified deficiencies but did not assess or correct the deficiencies. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					The Responsible Entity has implemented one or more documented process(es) for malicious code prevention, but where signatures or patterns are used, the Responsible Entity did not update malicious code protections and did not identify, assess, or correct the deficiencies. (3.3)	more documented process(es) for malicious code prevention but did not deploy method(s) to deter, detect, or prevent malicious code and did not identify, assess, or correct the deficiencies. (3.1)
R4	Same Day Operations and Operations Assessment	Medium	The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-	The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-	The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the	The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p>	<p>determined summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review and has identified deficiencies but did not assess or correct the deficiencies. (4.4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined</p>	<p>responsible entity) for the Applicable Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and has identified deficiencies but did not assess or correct the deficiencies. (4.2)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to generate alerts for necessary security events (as determined by the responsible entity) for the Applicable</p>	<p>identified deficiencies but did not assess or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R4 and did not identify, assess, or correct the deficiencies. (R4)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log events for the</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 22 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4)</p>	<p>summarization or sampling of logged events at least every 15 calendar days but missed an interval and completed the review within 30 calendar days of the prior review but did not identify, assess, or correct the deficiencies. (4.4)</p>	<p>Systems (per device or system capability) but did not generate alerts for all of the required types of events described in 4.2.1 through 4.2.2 and did not identify, assess, or correct the deficiencies. (4.2) OR The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event</p>	<p>Applicable Systems (per device or system capability) but did not detect and log all of the required types of events described in 4.1.1 through 4.1.3 and has identified deficiencies but did not assess or correct the deficiencies. (4.1) OR The Responsible Entity has documented and implemented one or more process(es) to log events for the Applicable Systems (per device or system capability) but did not detect and log all of the required types of</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>logs for at least the last 90 consecutive days and has identified deficiencies but did not assess or correct the deficiencies. (4.3)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented one or more process(es) to log applicable events identified in 4.1 (where technically feasible and except during CIP Exceptional Circumstances) but did not retain applicable event logs for at least the last 90 consecutive days and did not</p>	<p>events described in 4.1.1 through 4.1.3 and did not identify, assess, or correct the deficiencies. (4.1)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					identify, assess, or correct the deficiencies. (4.3) OR The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and has identified deficiencies but did not assess or correct the deficiencies. (4.4)	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					OR The Responsible Entity has documented and implemented one or more process(es) to identify undetected Cyber Security Incidents by reviewing an entity-determined summarization or sampling of logged events at least every 15 calendar days but missed two or more intervals and did not identify, assess, or correct the deficiencies. (4.4)	
R5	Operations Planning	Medium	The Responsible Entity has implemented one or more documented process(es) for password-only	The Responsible Entity has implemented one or more documented process(es) for password-only	The Responsible Entity has implemented one or more documented process(es) for System Access	The Responsible Entity did not implement or document one or more process(es) that included the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p>	<p>authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only</p>	<p>Controls but, did not include the identification or inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and has identified deficiencies but did not assess or correct the deficiencies. (5.2)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification or</p>	<p>applicable items in CIP-007-5(X) Table R5 and has identified deficiencies but did not assess or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity did not implement or document one or more process(es) that included the applicable items in CIP-007-5(X) Table R5 and did not identify, assess, or correct the deficiencies. (R5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 15 calendar months but less than or equal to 16 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)	authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 16 calendar months but less than or equal to 17 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)	inventory of all known enabled default or other generic account types, either by system, by groups of systems, by location, or by system type(s) and did not identify, assess, or correct the deficiencies. (5.2) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and has identified	more documented process(es) for System Access Controls but, where technically feasible, does not have a method(s) to enforce authentication of interactive user access and has identified deficiencies but did not assess or correct the deficiencies. (5.1) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, where technically feasible, does not have a

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					deficiencies but did not assess or correct the deficiencies. (5.3) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but, did not include the identification of the individuals with authorized access to shared accounts and did not identify, assess, or correct the deficiencies. (5.3) OR The Responsible Entity has implemented one or	method(s) to enforce authentication of interactive user access and did not identify, assess, or correct the deficiencies. (5.1) OR The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords and has identified deficiencies but did not assess or correct the deficiencies. (5.4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>more documented process(es) for password-only authentication for interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for</p>	<p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for System Access Controls but did not, per device capability, change known default passwords but did not identify, assess, or correct the deficiencies. (5.4)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>interactive user access that did not technically or procedurally enforce one of the two password parameters as described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to</p>	<p>did not technically or procedurally enforce all of the password parameters described in 5.5.1 and 5.5.2 and has identified deficiencies but did not assess or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but the Responsible Entity did not technically or procedurally enforce all of the</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and has identified deficiencies but did not assess or correct the deficiencies. (5.6)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to</p>	<p>password parameters described in 5.5.1 and 5.5.2 and did not identify, assess, or correct the deficiencies. (5.5)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and has</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					change the password within 17 calendar months but less than or equal to 18 calendar months of the last password change and did not identify, assess, or correct the deficiencies. (5.6)	identified deficiencies but did not assess or correct the deficiencies. (5.6) OR The Responsible Entity has implemented one or more documented process(es) for password-only authentication for interactive user access but did not technically or procedurally enforce password changes or an obligation to change the password within 18 calendar months of the last password change and did not identify, assess, or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						correct the deficiencies. (5.6) OR The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and has identified deficiencies but did not assess or correct the deficiencies. (5.7)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-007-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Responsible Entity has implemented one or more documented process(es) for System Access Control but, where technically feasible, did not either limit the number of unsuccessful authentication attempts or generate alerts after a threshold of unsuccessful authentication attempts and did not identify, assess, or correct the deficiencies. (5.7)

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Requirement R1 exists to reduce the attack surface of Cyber Assets by requiring entities to disable known unnecessary ports. The SDT intends for the entity to know what network accessible (“listening”) ports and associated services are accessible on their assets and systems, whether they are needed for that Cyber Asset’s function, and disable or restrict access to all other ports.

1.1. This requirement is most often accomplished by disabling the corresponding service or program that is listening on the port or configuration settings within the Cyber Asset. It can also be accomplished through using host-based firewalls, TCP_Wrappers, or other means on the Cyber Asset to restrict access. Note that the requirement is applicable at the Cyber Asset level. The Cyber Assets are those which comprise the applicable BES Cyber Systems and their associated Cyber Assets. This control is another layer in the defense against network-based attacks, therefore the SDT intends that the control be on the device itself, or positioned inline in a non-bypassable manner. Blocking ports at the ESP border does not substitute for this device level requirement. If a device has no provision for disabling or restricting logical ports on the device (example - purpose built devices that run from firmware with no port configuration available) then those ports that are open are deemed ‘needed.’

1.2. Examples of physical I/O ports include network, serial and USB ports external to the device casing. BES Cyber Systems should exist within a Physical Security Perimeter in which

case the physical I/O ports have protection from unauthorized access, but it may still be possible for accidental use such as connecting a modem, connecting a network cable that bridges networks, or inserting a USB drive. Ports used for 'console commands' primarily means serial ports on Cyber Assets that provide an administrative interface.

The protection of these ports can be accomplished in several ways including, but not limited to:

- Disabling all unneeded physical ports within the Cyber Asset's configuration
- Prominent signage, tamper tape, or other means of conveying that the ports should not be used without proper authorization
- Physical port obstruction through removable locks

This is a 'defense in depth' type control and it is acknowledged that there are other layers of control (the PSP for one) that prevent unauthorized personnel from gaining physical access to these ports. Even with physical access, it has been pointed out there are other ways to circumvent the control. This control, with its inclusion of means such as signage, is not meant to be a preventative control against intruders. Signage is indeed a directive control, not a preventative one. However, with a defense-in-depth posture, different layers and types of controls are required throughout the standard with this providing another layer for depth in Control Center environments. Once physical access has been achieved through the other preventative and detective measures by authorized personnel, a directive control that outlines proper behavior as a last line of defense are appropriate in these highest risk areas. In essence, signage would be used to remind authorized users to "think before you plug anything into one of these systems" which is the intent. This control is not designed primarily for intruders, but for example the authorized employee who intends to plug his possibly infected smartphone into an operator console USB port to charge the battery.

Requirement R2:

The SDT's intent of Requirement R2 is to require entities to know, track, and mitigate the known software vulnerabilities associated with their BES Cyber Assets. It is not strictly an "install every security patch" requirement; the main intention is to "be aware of in a timely manner and manage all known vulnerabilities" requirement.

Patch management is required for BES Cyber Systems that are accessible remotely as well as standalone systems. Stand alone systems are vulnerable to intentional or unintentional introduction of malicious code. A sound defense-in-depth security strategy employs additional measures such as physical security, malware prevention software, and software patch management to reduce the introduction of malicious code or the exploit of known vulnerabilities.

One or multiple processes could be utilized. An overall assessment process may exist in a top tier document with lower tier documents establishing the more detailed process followed for individual systems. Lower tier documents could be used to cover BES Cyber System nuances that may occur at the system level.

2.1. The Responsible Entity is to have a patch management program that covers tracking, evaluating, and installing cyber security patches. The requirement applies to patches only,

which are fixes released to handle a specific vulnerability in a hardware or software product. The requirement covers only patches that involve cyber security fixes and does not cover patches that are purely functionality related with no cyber security impact. Tracking involves processes for notification of the availability of new cyber security patches for the Cyber Assets. Documenting the patch source in the tracking portion of the process is required to determine when the assessment timeframe clock starts. This requirement handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system. The source can take many forms. The National Vulnerability Database, Operating System vendors, or Control System vendors could all be sources to monitor for release of security related patches, hotfixes, and/or updates. A patch source is not required for Cyber Assets that have no updateable software or firmware (there is no user accessible way to update the internal software or firmware executing on the Cyber Asset), or those Cyber Assets that have no existing source of patches such as vendors that no longer exist. The identification of these sources is intended to be performed once unless software is changed or added to the Cyber Asset's baseline.

2.2. Responsible Entities are to perform an assessment of security related patches within 35 days of release from their monitored source. An assessment should consist of determination of the applicability of each patch to the entity's specific environment and systems. Applicability determination is based primarily on whether the patch applies to a specific software or hardware component that the entity does have installed in an applicable Cyber Asset. A patch that applies to a service or component that is not installed in the entity's environment is not applicable. If the patch is determined to be non-applicable, that is documented with the reasons why and the entity is compliant. If the patch is applicable, the assessment can include a determination of the risk involved, how the vulnerability can be remediated, the urgency and timeframe of the remediation, and the steps the entity has previously taken or will take. Considerable care must be taken in applying security related patches, hotfixes, and/or updates or applying compensating measures to BES Cyber System or BES Cyber Assets that are no longer supported by vendors. It is possible security patches, hotfixes, and updates may reduce the reliability of the system, and entities should take this into account when determining the type of mitigation to apply. The Responsible Entities can use the information provided in the Department of Homeland Security "Quarterly Report on Cyber Vulnerabilities of Potential Risk to Control Systems" as a source. The DHS document "Recommended Practice for Patch Management of Control Systems" provides guidance on an evaluative process. It uses severity levels determined using the Common Vulnerability Scoring System Version 2. Determination that a security related patch, hotfix, and/or update poses too great a risk to install on a system or is not applicable due to the system configuration should not require a TFE.

When documenting the remediation plan measures it may not be necessary to document them on a one to one basis. The remediation plan measures may be cumulative. A measure to address a software vulnerability may involve disabling a particular service. That same service may be exploited through other software vulnerabilities. Therefore disabling the single service has addressed multiple patched vulnerabilities.

2.3. The requirement handles the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity either installs the patch or documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. There are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability. For those security related patches that are determined to be applicable, the Responsible Entity must within 35 days either install the patch, create a dated mitigation plan which will outline the actions to be taken or those that have already been taken by the Responsible Entity to mitigate the vulnerabilities addressed by the security patch, or revise an existing mitigation plan. Timeframes do not have to be designated as a particular calendar day but can have event designations such as “at next scheduled outage of at least two days duration.” “Mitigation plans” in the standard refers to internal documents and are not to be confused with plans that are submitted to Regional Entities in response to violations.

2.4. The entity has been notified of, has assessed, and has developed a plan to remediate the known risk and that plan must be implemented. Remediation plans that only include steps that have been previously taken are considered implemented upon completion of the documentation. Remediation plans that have steps to be taken to remediate the vulnerability must be implemented by the timeframe the entity documented in their plan. There is no maximum timeframe in this requirement as patching and other system changes carries its own risk to the availability and integrity of the systems and may require waiting until a planned outage. In periods of high demand or threatening weather, changes to systems may be curtailed or denied due to the risk to reliability.

Requirement R3:

3.1. Due to the wide range of equipment comprising the BES Cyber Systems and the wide variety of vulnerability and capability of that equipment to malware as well as the constantly evolving threat and resultant tools and controls, it is not practical within the standard to prescribe how malware is to be addressed on each Cyber Asset. Rather, the Responsible Entity determines on a BES Cyber System basis which Cyber Assets have susceptibility to malware intrusions and documents their plans and processes for addressing those risks and provides evidence that they follow those plans and processes. There are numerous options available including traditional antivirus solutions for common operating systems, white-listing solutions, network isolation techniques, portable storage media policies, Intrusion Detection/Prevention (IDS/IPS) solutions, etc. If an entity has numerous BES Cyber Systems or Cyber Assets that are of identical architecture, they may provide one process that describes how all the like Cyber Assets are covered. If a specific Cyber Asset has no updateable software and its executing code cannot be altered, then that Cyber Asset is considered to have its own internal method of deterring malicious code.

3.2. When malicious code is detected on a Cyber Asset within the applicability of this requirement, the threat posed by that code must be mitigated. In situations where traditional antivirus products are used, they may be configured to automatically remove or quarantine the malicious code. In white-listing situations, the white-listing tool itself can mitigate the threat as

it will not allow the code to execute, however steps should still be taken to remove the malicious code from the Cyber Asset. In some instances, it may be in the best interest of reliability to not immediately remove or quarantine the malicious code, such as when availability of the system may be jeopardized by removal while operating and a rebuild of the system needs to be scheduled. In that case, monitoring may be increased and steps taken to insure the malicious code cannot communicate with other systems. In some instances the entity may be working with law enforcement or other governmental entities to closely monitor the code and track the perpetrator(s). For these reasons, there is no maximum timeframe or method prescribed for the removal of the malicious code, but the requirement is to mitigate the threat posed by the now identified malicious code.

3.3. In instances where malware detection technologies depend on signatures or patterns of known attacks, the effectiveness of these tools against evolving threats is tied to the ability to keep these signatures and patterns updated in a timely manner. The entity is to have a documented process that includes the testing and installation of signature or pattern updates. In a BES Cyber System, there may be some Cyber Assets that would benefit from the more timely installation of the updates where availability of that Cyber Asset would not jeopardize the availability of the BES Cyber System's ability to perform its function. For example, some HMI workstations where portable media is utilized may benefit from having the very latest updates at all times with minimal testing. Other Cyber Assets should have any updates thoroughly tested before implementation where the result of a 'false positive' could harm the availability of the BES Cyber System. The testing should not negatively impact the reliability of the BES. The testing should be focused on the update itself and if it will have an adverse impact on the BES Cyber System. Testing in no way implies that the entity is testing to ensure that malware is indeed detected by introducing malware into the environment. It is strictly focused on ensuring that the update does not negatively impact the BES Cyber System before those updates are placed into production.

Requirement R4:

Refer to NIST 800-92 and 800-137 for additional guidance in security event monitoring.

4.1. In a complex computing environment and faced with dynamic threats and vulnerabilities, it is not practical within the standard to enumerate all security-related events necessary to support the activities for alerting and incident response. Rather, the Responsible Entity determines which computer generated events are necessary to log, provide alerts and monitor for their particular BES Cyber System environment.

Specific security events already required in Version 4 of the CIP Standards carry forward in this version. This includes access attempts at the Electronic Access Points, if any have been identified for a BES Cyber Systems. Examples of access attempts include: (i) blocked network access attempts, (ii) successful and unsuccessful remote user access attempts, (iii) blocked network access attempts from a remote VPN, and (iv) successful network access attempts or network flow information.

User access and activity events include those events generated by Cyber Assets within the Electronic Security Perimeter that have access control capability. These types of events include:

(i) successful and unsuccessful authentication, (ii) account management, (iii) object access, and (iv) processes started and stopped.

It is not the intent of the SDT that if a device cannot log a particular event that a TFE must be generated. The SDT's intent is that if any of the items in the bulleted list (for example, user logouts) can be logged by the device then the entity must log that item. If the device does not have the capability of logging that event, the entity remains compliant.

4.2. Real-time alerting allows the cyber system to automatically communicate events of significance to designated responders. This involves configuration of a communication mechanism and log analysis rules. Alerts can be configured in the form of an email, text message, or system display and alarming. The log analysis rules can exist as part of the operating system, specific application or a centralized security event monitoring system. On one end, a real-time alert could consist of a set point on an RTU for a login failure, and on the other end, a security event monitoring system could provide multiple alerting communications options triggered on any number of complex log correlation rules.

The events triggering a real-time alert may change from day to day as system administrators and incident responders better understand the types of events that might be indications of a cyber-security incident. Configuration of alerts also must balance the need for responders to know an event occurred with the potential inundation of insignificant alerts. The following list includes examples of events a Responsible Entity should consider in configuring real-time alerts:

- Detected known or potential malware or malicious activity
- Failure of security event logging mechanisms
- Login failures for critical accounts
- Interactive login of system accounts
- Enabling of accounts
- Newly provisioned accounts
- System administration or change tasks by an unauthorized user
- Authentication attempts on certain accounts during non-business hours
- Unauthorized configuration changes
- Insertion of removable media in violation of a policy

4.3 Logs that are created under Part 4.1 are to be retained on the applicable Cyber Assets or BES Cyber Systems for at least 90 days. This is different than the evidence retention period called for in the CIP standards used to prove historical compliance. For such audit purposes, the entity should maintain evidence that shows that 90 days were kept historically. One example would be records of disposition of event logs beyond 90 days up to the evidence retention period.

4.4. Reviewing logs at least every 15 days (approximately every two weeks) can consist of analyzing a summarization or sampling of logged events. NIST SP800-92 provides a lot of guidance in periodic log analysis. If a centralized security event monitoring system is used, log analysis can be performed top-down starting with a review of trends from summary reports.

The log review can also be an extension of the exercise in identifying those events needing real-time alerts by analyzing events that are not fully understood or could possibly inundate the real-time alerting.

Requirement R5:

Account types referenced in this guidance typically include:

- Shared user account: An account used by multiple users for normal business functions by employees or contractors. Usually on a device that does not support Individual User Accounts.
- Individual user account: An account used by a single user.
- Administrative account: An account with elevated privileges for performing administrative or other specialized functions. These can be individual or shared accounts.
- System account: Accounts used to run services on a system (web, DNS, mail etc). No users have access to these accounts.
- Application account: A specific system account, with rights granted at the application level often used for access into a Database.
- Guest account: An individual user account not typically used for normal business functions by employees or contractors and not associated with a specific user. May or may not be shared by multiple users.
- Remote access account: An individual user account only used for obtaining Interactive Remote Access to the BES Cyber System.
- Generic account: A group account set up by the operating system or application to perform specific operations. This differs from a shared user account in that individual users do not receive authorization for access to this account type.

5.1 Reference the Requirement's rationale.

5.2 Where possible, default and other generic accounts provided by a vendor should be removed, renamed, or disabled prior to production use of the Cyber Asset or BES Cyber System. If this is not possible, the passwords must be changed from the default provided by the vendor. Default and other generic accounts remaining enabled must be documented. For common configurations, this documentation can be performed at a BES Cyber System or more general level.

5.3 Entities may choose to identify individuals with access to shared accounts through the access authorization and provisioning process, in which case the individual authorization records suffice to meet this Requirement Part. Alternatively, entities may choose to maintain a separate listing for shared accounts. Either form of evidence achieves the end result of maintaining control of shared accounts.

5.4. Default passwords can be commonly published in vendor documentation that is readily available to all customers using that type of equipment and possibly published online.

The requirement option to have unique password addresses cases where the Cyber Asset generates or has assigned pseudo-random default passwords at the time of production or installation. In these cases, the default password does not have to change because the system or manufacturer created it specific to the Cyber Asset.

5.5. Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Technical or procedural enforcement of password parameters are required where passwords are the only credential used to authenticate individuals. Technical enforcement of the password parameters means a Cyber Asset verifies an individually selected password meets the required parameters before allowing the account to authenticate with the selected password. Technical enforcement should be used in most cases when the authenticating Cyber Asset supports enforcing password parameters. Likewise, procedural enforcement means requiring the password parameters through procedures. Individuals choosing the passwords have the obligation of ensuring the password meets the required parameters.

Password complexity refers to the policy set by a Cyber Asset to require passwords to have one or more of the following types of characters: (1) lowercase alphabetic, (2) uppercase alphabetic, (3) numeric, and (4) non-alphanumeric or “special” characters (e.g. #, \$, @, &), in various combinations.

5.6 Technical or procedural enforcement of password change obligations are required where passwords are the only credential used to authenticate individuals. Technical enforcement of password change obligations means the Cyber Asset requires a password change after a specified timeframe prior to allowing access. In this case, the password is not required to change by the specified time as long as the Cyber Asset enforces the password change after the next successful authentication of the account. Procedural enforcement means manually changing passwords used for interactive user access after a specified timeframe.

5.7 Configuring an account lockout policy or alerting after a certain number of failed authentication attempts serves to prevent unauthorized access through an online password guessing attack. The threshold of failed authentication attempts should be set high enough to avoid false-positives from authorized users failing to authenticate. It should also be set low enough to account for online password attacks occurring over an extended period of time. This threshold may be tailored to the operating environment over time to avoid unnecessary account lockouts.

Entities should take caution when configuring account lockout to avoid locking out accounts necessary for the BES Cyber System to perform a BES reliability task. In such cases, entities should configure authentication failure alerting.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The requirement is intended to minimize the attack surface of BES Cyber Systems through disabling or limiting access to unnecessary network accessible logical ports and services and physical I/O ports.

Summary of Changes: Changed the ‘needed for normal or emergency operations’ to those ports that are needed. Physical I/O ports were added in response to a FERC order. The unneeded physical ports in Control Centers (which are the highest risk, most impactful areas) should be protected as well.

Reference to prior version: (Part 1.1) CIP-007-4, R2.1 and R2.2

Change Rationale: (Part 1.1)

The requirement focuses on the entity knowing and only allowing those ports that are necessary. The additional classification of ‘normal or emergency’ added no value and has been removed.

Reference to prior version: (Part 1.2) New

Change Rationale: (Part 1.2)

On March 18, 2010, FERC issued an order to approve NERC’s interpretation of Requirement R2 of CIP-007-2. In this order, FERC agreed the term “ports” in “ports and services” refers to logical communication (e.g. TCP/IP) ports, but they also encouraged the drafting team to address unused physical ports.

Rationale for R2:

Security patch management is a proactive way of monitoring and addressing known security vulnerabilities in software before those vulnerabilities can be exploited in a malicious manner to gain control of or render a BES Cyber Asset or BES Cyber System inoperable.

The remediation plan can be updated as necessary to maintain the reliability of the BES, including an explanation of any rescheduling of the remediation actions.

Summary of Changes: The existing wordings of CIP-007, Requirements R3, R3.1, and R3.2, were separated into individual line items to provide more granularity. The documentation of a source(s) to monitor for release of security related patches, hot fixes, and/or updates for BES Cyber System or BES Cyber Assets was added to provide context as to when the “release” date was. The current wording stated “document the assessment of security patches and security

upgrades for applicability within thirty calendar days of availability of the patches or upgrades” and there has been confusion as to what constitutes the availability date. Due to issues that may occur regarding Control System vendor license and service agreements, flexibility must be given to Responsible Entities to define what sources are being monitored for BES Cyber Assets.

Reference to prior version: (Part 2.1) CIP-007, R3

Change Rationale: (Part 2.1)

The requirement is brought forward from previous CIP versions with the addition of defining the source(s) that a Responsible Entity monitors for the release of security related patches. Documenting the source is used to determine when the assessment timeframe clock starts. This requirement also handles the situation where security patches can come from an original source (such as an operating system vendor), but must be approved or certified by another source (such as a control system vendor) before they can be assessed and applied in order to not jeopardize the availability or integrity of the control system.

Reference to prior version: (Part 2.2) CIP-007, R3.1

Change Rationale: (Part 2.2)

Similar to the current wording but added “from the source or sources identified in 2.1” to clarify the 35-day time frame.

Reference to prior version: (Part 2.3) CIP-007, R3.2

Change Rationale: (Part 2.3)

The requirement has been changed to handle the situations where it is more of a reliability risk to patch a running system than the vulnerability presents. In all cases, the entity documents (either through the creation of a new or update of an existing mitigation plan) what they are going to do to mitigate the vulnerability and when they are going to do so. The mitigation plan may, and in many cases will, consist of installing the patch. However, there are times when it is in the best interest of reliability to not install a patch, and the entity can document what they have done to mitigate the vulnerability.

Reference to prior version: (Part 2.4) CIP-007, R3.2

Change Rationale: (Part 2.4)

Similar to the current wording but added that the plan must be implemented within the timeframe specified in the plan, or in a revised plan as approved by the CIP Senior Manager or delegate.

Rationale for R3:

Malicious code prevention has the purpose of limiting and detecting the addition of malicious code onto the applicable Cyber Assets of a BES Cyber System. Malicious code (viruses, worms, botnets, targeted code such as Stuxnet, etc.) may compromise the availability or integrity of the BES Cyber System.

Summary of Changes: In prior versions, this requirement has arguably been the single greatest generator of TFEs as it prescribed a particular technology to be used on every CCA regardless of

that asset's susceptibility or capability to use that technology. As the scope of Cyber Assets in scope of these standards expands to more field assets, this issue will grow exponentially. The drafting team is taking the approach of making this requirement a competency based requirement where the entity must document how the malware risk is handled for each BES Cyber System, but it does not prescribe a particular technical method nor does it prescribe that it must be used on every Cyber Asset. The BES Cyber System is the object of protection.

Beginning in Paragraphs 619-622 of FERC Order No. 706, and in particular Paragraph 621, FERC agrees that the standard "does not need to prescribe a single method...However, how a responsible entity does this should be detailed in its cyber security policy so that it can be audited for compliance..."

In Paragraph 622, FERC directs that the requirement be modified to include safeguards against personnel introducing, either maliciously or unintentionally, viruses or malicious software through remote access, electronic media, or other means. The drafting team believes that addressing this issue holistically at the BES Cyber System level and regardless of technology, along with the enhanced change management requirements, meets this directive.

Reference to prior version: (Part 3.1) CIP-007-4, R4; CIP-007-4, R4.1

Change Rationale: (Part 3.1)

See the Summary of Changes. FERC Order No. 706, Paragraph 621, states the standards development process should decide to what degree to protect BES Cyber Systems from personnel introducing malicious software.

Reference to prior version: (Part 3.2) CIP-007-4, R4; CIP-007-4, R4.1

Change Rationale: (Part 3.2)

See the Summary of Changes.

Reference to prior version: (Part 3.3) CIP-007-4, R4; CIP-007-4, R4.2

Change Rationale: (Part 3.3)

Requirement essentially unchanged from previous versions; updated to refer to previous parts of the requirement table.

Rationale for R4:

Rationale for R4: Security event monitoring has the purpose of detecting unauthorized access, reconnaissance and other malicious activity on BES Cyber Systems, and comprises of the activities involved with the collection, processing, alerting and retention of security-related computer logs. These logs can provide both (1) the detection of an incident and (2) useful evidence in the investigation of an incident. The retention of security-related logs is intended to support post-event data analysis.

Audit processing failures are not penalized in this requirement. Instead, the requirement specifies processes which must be in place to monitor for and notify personnel of audit processing failures.

Summary of Changes: Beginning in Paragraph 525 and also Paragraph 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis. This requirement combines CIP-005-4, R5 and CIP-007-4, R6 and addresses both directives from a system-wide perspective. The primary feedback received on this requirement from the informal comment period was the vagueness of terms “security event” and “monitor.”

The term “security event” or “events related to cyber security” is problematic because it does not apply consistently across all platforms and applications. To resolve this term, the requirement takes an approach similar to NIST 800-53 and requires the entity to define the security events relevant to the System. There are a few events explicitly listed that if a Cyber Asset or BES Cyber System can log, then it must log.

In addition, this requirement sets up parameters for the monitoring and reviewing of processes. It is rarely feasible or productive to look at every security log on the system. Paragraph 629 of the FERC Order No. 706 acknowledges this reality when directing a manual log review. As a result, this requirement allows the manual review to consist of a sampling or summarization of security events occurring since the last review.

Reference to prior version: (Part 4.1) CIP-005-4, R3; CIP-007-4, R5, R5.1.2, R6.1, and R6.3

Change Rationale: (Part 4.1)

This requirement is derived from NIST 800-53 version 3 AU-2, which requires organizations to determine system events to audit for incident response purposes. The industry expressed confusion in the term “system events related to cyber security” from informal comments received on CIP-011. Access logs from the ESP as required in CIP-005-4 Requirement R3 and user access and activity logs as required in CIP-007-5 Requirement R5 are also included here.

Reference to prior version: (Part 4.2) CIP-005-4, R3.2; CIP-007-4, R6.2

Change Rationale: (Part 4.2)

This requirement is derived from alerting requirements in CIP-005-4, Requirement R3.2 and CIP-007-4, Requirement R6.2 in addition to NIST 800-53 version 3 AU-6. Previous CIP Standards required alerting on unauthorized access attempts and detected Cyber Security Incidents, which can be vast and difficult to determine from day to day. Changes to this requirement allow the entity to determine events that necessitate a response.

Reference to prior version: (Part 4.3) CIP-005-4, R3.2; CIP-007-4, R6.4

Change Rationale: (Part 4.3)

No substantive change.

Reference to prior version: (Part 4.4) CIP-005-4, R3.2; CIP-007-4, R6.5

Change Rationale: (Part 4.4)

Beginning in Paragraph 525 and also 628 of the FERC Order No. 706, the Commission directs a manual review of security event logs on a more periodic basis and suggests a weekly review. The Order acknowledges it is rarely feasible to review all system logs. Indeed, log review is a dynamic process that should improve over time and with additional threat information.

Changes to this requirement allow for an approximately biweekly summary or sampling review of logs.

Rationale for R5:

To help ensure that no authorized individual can gain electronic access to a BES Cyber System until the individual has been authenticated, i.e., until the individual's logon credentials have been validated. Requirement R5 also seeks to reduce the risk that static passwords, where used as authenticators, may be compromised.

Requirement Part 5.1 ensures the BES Cyber System or Cyber Asset authenticates individuals that can modify configuration information. This requirement addresses the configuration of authentication. The authorization of individuals is addressed elsewhere in the CIP Cyber Security Standards. Interactive user access does not include read-only information access in which the configuration of the Cyber Asset cannot change (e.g. front panel displays, web-based reports, etc.). For devices that cannot technically or for operational reasons perform authentication, an entity may demonstrate all interactive user access paths, both remote and local, are configured for authentication. Physical security suffices for local access configuration if the physical security can record who is in the Physical Security Perimeter and at what time.

Requirement Part 5.2 addresses default and other generic account types. Identifying the use of default or generic account types that could introduce vulnerabilities has the benefit ensuring entities understand the possible risk these accounts pose to the BES Cyber System. The Requirement Part avoids prescribing an action to address these accounts because the most effective solution is situation specific, and in some cases, removing or disabling the account could have reliability consequences.

Requirement Part 5.3 addresses identification of individuals with access to shared accounts. This Requirement Part has the objective of mitigating the risk of unauthorized access through shared accounts. This differs from other CIP Cyber Security Standards Requirements to authorize access. An entity can authorize access and still not know who has access to a shared account. Failure to identify individuals with access to shared accounts would make it difficult to revoke access when it is no longer needed. The term "authorized" is used in the requirement to make clear that individuals storing, losing, or inappropriately sharing a password is not a violation of this requirement.

Requirement 5.4 addresses default passwords. Changing default passwords closes an easily exploitable vulnerability in many systems and applications. Pseudo-randomly system generated passwords are not considered default passwords.

For password-based user authentication, using strong passwords and changing them periodically helps mitigate the risk of successful password cracking attacks and the risk of accidental password disclosure to unauthorized individuals. In these requirements, the drafting team considered multiple approaches to ensuring this requirement was both effective and flexible enough to allow Responsible Entities to make good security decisions. One of the approaches considered involved requiring minimum password entropy, but the calculation for

true information entropy is more highly complex and makes several assumptions in the passwords users choose. Users can pick poor passwords well below the calculated minimum entropy.

The drafting team also chose to not require technical feasibility exceptions for devices that cannot meet the length and complexity requirements in password parameters. The objective of this requirement is to apply a measurable password policy to deter password cracking attempts, and replacing devices to achieve a specified password policy does not meet this objective. At the same time, this requirement has been strengthened to require account lockout or alerting for failed login attempts, which in many instances better meets the requirement objective.

The requirement to change passwords exists to address password cracking attempts if an encrypted password were somehow attained and also to refresh passwords which may have been accidentally disclosed over time. The requirement permits the entity to specify the periodicity of change to accomplish this objective. Specifically, the drafting team felt determining the appropriate periodicity based on a number of factors is more effective than specifying the period for every BES Cyber System in the Standard. In general, passwords for user authentication should be changed at least annually. The periodicity may increase in some cases. For example, application passwords that are long and pseudo-randomly generated could have a very long periodicity. Also, passwords used only as a weak form of application authentication, such as accessing the configuration of a relay may only need to be changed as part of regularly scheduled maintenance.

The Cyber Asset should automatically enforce the password policy for individual user accounts. However, for shared accounts in which no mechanism exists to enforce password policies, the Responsible Entity can enforce the password policy procedurally and through internal assessment and audit.

Requirement Part 5.7 assists in preventing online password attacks by limiting the number of guesses an attacker can make. This requirement allows either limiting the number of failed authentication attempts or alerting after a defined number of failed authentication attempts. Entities should take caution in choosing to limit the number of failed authentication attempts for all accounts because this would allow the possibility for a denial of service attack on the BES Cyber System.

Summary of Changes (From R5):

CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. For example, many have interpreted the password for tokens or biometrics must satisfy this policy and in some cases prevents the use of this stronger authentication. Also, longer passwords may preclude the use of strict complexity requirements. The password requirements have been changed to allow the entity to specify the most effective password parameters based on the impact of the BES Cyber System, the way passwords are used, and the significance of passwords in restricting access to the system. The SDT believes these changes strengthen the authentication

mechanism by requiring entities to look at the most effective use of passwords in their environment. Otherwise, prescribing a strict password policy has the potential to limit the effectiveness of security mechanisms and preclude better mechanisms in the future.

Reference to prior version: (Part 5.1) CIP-007-4, R5

Change Rationale: (Part 5.1)

The requirement to enforce authentication for all user access is included here. The requirement to establish, implement, and document controls is included in this introductory requirement. The requirement to have technical and procedural controls was removed because technical controls suffice when procedural documentation is already required. The phrase “that minimize the risk of unauthorized access” was removed and more appropriately captured in the rationale statement.

Reference to prior version: (Part 5.2) CIP-007-4, R5.2 and R5.2.1

Change Rationale: (Part 5.2)

CIP-007-4 requires entities to minimize and manage the scope and acceptable use of account privileges. The requirement to minimize account privileges has been removed because the implementation of such a policy is difficult to measure at best.

Reference to prior version: (Part 5.3) CIP-007-4, R5.2.2

Change Rationale: (Part 5.3)

No significant changes. Added “authorized” access to make clear that individuals storing, losing or inappropriately sharing a password is not a violation of this requirement.

Reference to prior version: (Part 5.4) CIP-007-4, R5.2.1

Change Rationale: (Part 5.4)

The requirement for the “removal, disabling or renaming of such accounts where possible” has been removed and incorporated into guidance for acceptable use of account types. This was removed because those actions are not appropriate on all account types. Added the option of having unique default passwords to permit cases where a system may have generated a default password or a hard-coded uniquely generated default password was manufactured with the BES Cyber System.

Reference to prior version: (Part 5.5) CIP-007-4, R5.3

Change Rationale: (Part 5.5)

CIP-007-4, Requirement R5.3 requires the use of passwords and specifies a specific policy of six characters or more with a combination of alpha-numeric and special characters. The level of detail in these requirements can restrict more effective security measures. The password requirements have been changed to permit the maximum allowed by the device in cases where the password parameters could otherwise not achieve a stricter policy. This change still achieves the requirement objective to minimize the risk of unauthorized disclosure of password

credentials while recognizing password parameters alone do not achieve this. The drafting team felt allowing the Responsible Entity the flexibility of applying the strictest password policy allowed by a device outweighed the need to track a relatively minimally effective control through the TFE process.

Reference to prior version: (Part 5.6) CIP-007-4, R5.3.3

Change Rationale: (Part 5.6)

**This was originally Requirement R5.5.3, but moved to add “external routable connectivity” to medium impact in response to comments. This requirement is limited in scope because the risk to performing an online password attack is lessened by its lack of external routable connectivity. Frequently changing passwords at field assets can entail significant effort with minimal risk reduction.*

Reference to prior version: (Part 5.7) New Requirement

Change Rationale: (Part 5.7)

Minimizing the number of unsuccessful login attempts significantly reduces the risk of live password cracking attempts. This is a more effective control in live password attacks than password parameters.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	

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3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-007-5. (Order becomes effective on 2/3/14.)	
<u>5(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning
2. **Number:** CIP-008-5(X)
3. **Purpose:** To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**
 - 4.1.8 **Transmission Owner**

- 4.2. Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.
- 4.2.1 Distribution Provider:** One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:
- 4.2.1.1** Each UFLS or UVLS System that:
- 4.2.1.1.1** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.2.1.1.2** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
- 4.2.1.2** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
- 4.2.1.3** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
- 4.2.1.4** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
- 4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:**
All BES Facilities.
- 4.2.3 Exemptions:** The following are exempt from Standard CIP-008-5(X):
- 4.2.3.1** Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
 - 4.2.3.2** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.
 - 4.2.3.3** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.
 - 4.2.3.4** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.
 - 4.2.3.5** Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-008-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-008-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-008-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

B. Requirements and Measures

- R1.** Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*.
[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning].
- M1.** Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*.

CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	One or more processes to identify, classify, and respond to Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation of Cyber Security Incident response plan(s) that include the process to identify, classify, and respond to Cyber Security Incidents.
1.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	One or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a Reportable Cyber Security Incident.	Examples of evidence may include, but are not limited to, dated documentation of Cyber Security Incident response plan(s) that provide guidance or thresholds for determining which Cyber Security Incidents are also Reportable Cyber Security Incidents and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).

CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.3	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	The roles and responsibilities of Cyber Security Incident response groups or individuals.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that define roles and responsibilities (e.g., monitoring, reporting, initiating, documenting, etc.) of Cyber Security Incident response groups or individuals.
1.4	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Incident handling procedures for Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).

- R2.** Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations].
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*.

CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Test each Cyber Security Incident response plan(s) at least once every 15 calendar months: <ul style="list-style-type: none"> • By responding to an actual Reportable Cyber Security Incident; • With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or • With an operational exercise of a Reportable Cyber Security Incident. 	Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises.

CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise.	Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.
2.3	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Retain records related to Reportable Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to Reportable Cyber Security Incidents.

- R3.** Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].
- M3.** Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each Cyber Security Incident response plan according to the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident*.

CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	Applicable Systems	Requirements	Measures
3.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	<p>No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response:</p> <p>3.1.1. Document any lessons learned or document the absence of any lessons learned;</p> <p>3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and</p> <p>3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.</p>	<p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> 1. Dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response or dated documentation stating there were no lessons learned; 2. Dated and revised Cyber Security Incident response plan showing any changes based on the lessons learned; and 3. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	Applicable Systems	Requirements	Measures
3.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	<p>No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan:</p> <p>3.2.1. Update the Cyber Security Incident response plan(s); and</p> <p>3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.</p>	<p>An example of evidence may include, but is not limited to:</p> <ol style="list-style-type: none"> 1. Dated and revised Cyber Security Incident response plan with changes to the roles or responsibilities, responders or technology; and 2. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long Term Planning	Lower	N/A	N/A	<p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3)</p> <p>OR</p> <p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4)</p>	<p>The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents. (1.2)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but did</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						not provide at least preliminary notification to ES-ISAC within one hour from identification of a Reportable Cyber Security Incident. (1.2)
R2	Operations Planning Real-time Operations	Lower	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 15 calendar months, not exceeding 16 calendar months between tests of the plan. (2.1)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan. (2.1)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 17 calendar months, not exceeding 18 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not document deviations, if any, from the plan during a test or when a Reportable Cyber Security Incident occurs. (2.2)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 19 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not retain relevant records related to Reportable Cyber Security Incidents. (2.3)
R3	Operations Assessment	Lower	The Responsible Entity has not notified each person or group with	The Responsible Entity has not updated the	The Responsible Entity has neither	The Responsible Entity has neither

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within greater than 90 but less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)	Cyber Security Incident response plan based on any documented lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2) OR The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3) OR	documented lessons learned nor documented the absence of any lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1) OR The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2) OR The Responsible Entity has not updated the	documented lessons learned nor documented the absence of any lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes. 	<p>Cyber Security Incident response plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes. 	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:

- Department of Homeland Security, Control Systems Security Program, *Developing an Industrial Control Systems Cyber Security Incident Response Capability*, 2009, online at http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf
- National Institute of Standards and Technology, *Computer Security Incident Handling Guide*, Special Publication 800-61 revision 1, March 2008, online at <http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf>

For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action. A response action can fall into one of two categories: Necessary or elective. The distinguishing characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.

The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.

Requirement R2:

Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for *Reportable Cyber Security Incidents*.

Entities may use an actual response to a *Reportable Cyber Security Incident* as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, “A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures.”

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, “[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and ‘boots on the ground’ response (e.g., firefighters decontaminating mock victims).”

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for *Reportable Cyber Security Incidents*. There are several examples of specific types of evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.

Requirement R3:

This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.

The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response

activities. The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.

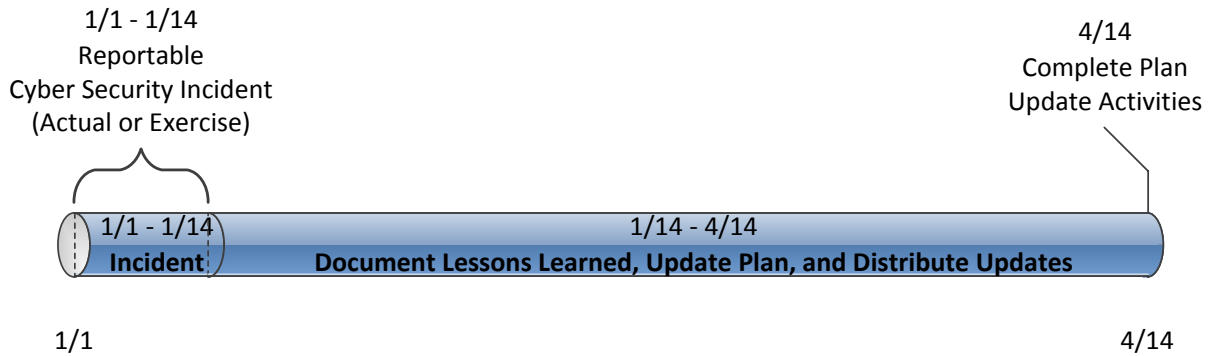


Figure 1: CIP-008-5(X) R3 Timeline for Reportable Cyber Security Incidents

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.

The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.

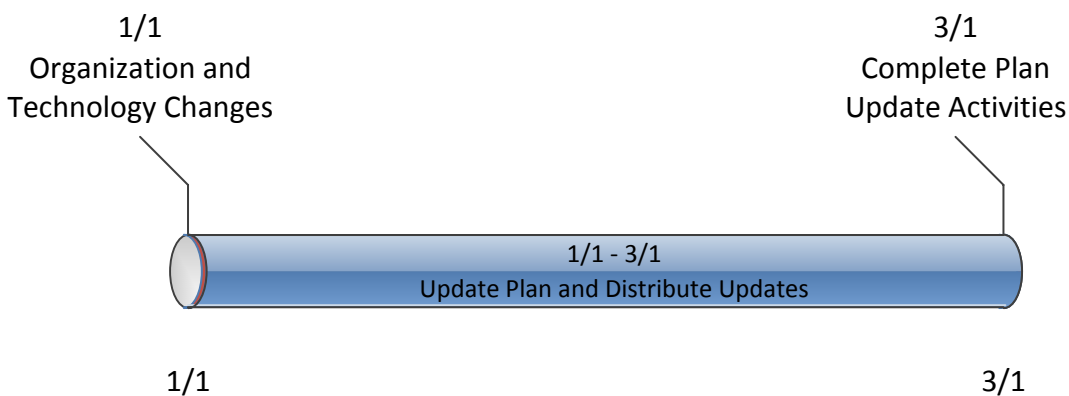


Figure 2: Timeline for Plan Changes in 3.2

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services. An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement. An organization may have a common plan for multiple registered entities it owns.

Summary of Changes: Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.

Reference to prior version: (Part 1.1) CIP-008, R1.1

Change Description and Justification: (Part 1.1)

“Characterize” has been changed to “identify” for clarity. “Response actions” has been changed to “respond to” for clarity.

Reference to prior version: (Part 1.2) CIP-008, R1.1

Change Description and Justification: (Part 1.2)

Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).

Reference to prior version: (Part 1.3) CIP-008, R1.2

Change Description and Justification: (Part 1.3)

Replaced incident response teams with incident response “groups or individuals” to avoid the interpretation that roles and responsibilities sections must reference specific teams.

Reference to prior version: (Part 1.4) CIP-008, R1.2

Change Description and Justification: (Part 1.4)

Conforming change to reference new defined term Cyber Security Incidents.

Rationale for R2:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.

This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only. If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

Summary of Changes: Added testing requirements to verify the Responsible Entity’s response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

Reference to prior version: (Part 2.1) CIP-008, R1.6

Change Description and Justification: (Part 2.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-008, R1.6

Change Description and Justification: (Part 2.2)

Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.

Reference to prior version: (Part 2.3) CIP-008, R2

Change Description and Justification: (Part 2.3)

Removed references to the retention period because the Standard addresses data retention in the Compliance Section.

Rationale for R3:

Conduct sufficient reviews, updates and communications to verify the Responsible Entity’s response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.

Summary of Changes: Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the

plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.

Reference to prior version: (Part 3.1) CIP-008, R1.5

Change Description and Justification: (Part 3.1)

Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.

Reference to prior version: (Part 3.2) CIP-008, R1.4

Change Description and Justification: (Part 3.2)

Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	

Guidelines and Technical Basis

4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-008-5. (Order becomes effective on 2/3/14.)	
5(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — Incident Reporting and Response Planning
2. **Number:** CIP-008-5(X)
3. **Purpose:** To mitigate the risk to the reliable operation of the BES as the result of a Cyber Security Incident by specifying incident response requirements.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-008-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-008-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-008-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-008-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.

B. Requirements and Measures

- R1.** Each Responsible Entity shall document one or more Cyber Security Incident response plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*.
- M1.** Evidence must include each of the documented plan(s) that collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications*.

CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	One or more processes to identify, classify, and respond to Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation of Cyber Security Incident response plan(s) that include the process to identify, classify, and respond to Cyber Security Incidents.
1.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	One or more processes to determine if an identified Cyber Security Incident is a Reportable Cyber Security Incident and notify the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), unless prohibited by law. Initial notification to the ES-ISAC, which may be only a preliminary notice, shall not exceed one hour from the determination of a Reportable Cyber Security Incident.	Examples of evidence may include, but are not limited to, dated documentation of Cyber Security Incident response plan(s) that provide guidance or thresholds for determining which Cyber Security Incidents are also Reportable Cyber Security Incidents and documentation of initial notices to the Electricity Sector Information Sharing and Analysis Center (ES-ISAC).

CIP-008-5(X) Table R1 – Cyber Security Incident Response Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.3	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	The roles and responsibilities of Cyber Security Incident response groups or individuals.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that define roles and responsibilities (e.g., monitoring, reporting, initiating, documenting, etc.) of Cyber Security Incident response groups or individuals.
1.4	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Incident handling procedures for Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated Cyber Security Incident response process(es) or procedure(s) that address incident handling (e.g., containment, eradication, recovery/incident resolution).

- R2.** Each Responsible Entity shall implement each of its documented Cyber Security Incident response plans to collectively include each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-Time Operations].
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing*.

CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Test each Cyber Security Incident response plan(s) at least once every 15 calendar months: <ul style="list-style-type: none"> • By responding to an actual Reportable Cyber Security Incident; • With a paper drill or tabletop exercise of a Reportable Cyber Security Incident; or • With an operational exercise of a Reportable Cyber Security Incident. 	Examples of evidence may include, but are not limited to, dated evidence of a lessons-learned report that includes a summary of the test or a compilation of notes, logs, and communication resulting from the test. Types of exercises may include discussion or operations based exercises.

CIP-008-5(X) Table R2 – Cyber Security Incident Response Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Use the Cyber Security Incident response plan(s) under Requirement R1 when responding to a Reportable Cyber Security Incident or performing an exercise of a Reportable Cyber Security Incident. Document deviations from the plan(s) taken during the response to the incident or exercise.	Examples of evidence may include, but are not limited to, incident reports, logs, and notes that were kept during the incident response process, and follow-up documentation that describes deviations taken from the plan during the incident or exercise.
2.3	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	Retain records related to Reportable Cyber Security Incidents.	An example of evidence may include, but is not limited to, dated documentation, such as security logs, police reports, emails, response forms or checklists, forensic analysis results, restoration records, and post-incident review notes related to Reportable Cyber Security Incidents.

- R3.** Each Responsible Entity shall maintain each of its Cyber Security Incident response plans according to each of the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication*. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].
- M3.** Evidence must include, but is not limited to, documentation that collectively demonstrates maintenance of each Cyber Security Incident response plan according to the applicable requirement parts in *CIP-008-5(X) Table R3 – Cyber Security Incident*.

CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	Applicable Systems	Requirements	Measures
3.1	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	<p>No later than 90 calendar days after completion of a Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response:</p> <p>3.1.1. Document any lessons learned or document the absence of any lessons learned;</p> <p>3.1.2. Update the Cyber Security Incident response plan based on any documented lessons learned associated with the plan; and</p> <p>3.1.3. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates to the Cyber Security Incident response plan based on any documented lessons learned.</p>	<p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> 1. Dated documentation of post incident(s) review meeting notes or follow-up report showing lessons learned associated with the Cyber Security Incident response plan(s) test or actual Reportable Cyber Security Incident response or dated documentation stating there were no lessons learned; 2. Dated and revised Cyber Security Incident response plan showing any changes based on the lessons learned; and 3. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

CIP-008-5(X) Table R3 – Cyber Security Incident Response Plan Review, Update, and Communication			
Part	Applicable Systems	Requirements	Measures
3.2	High Impact BES Cyber Systems Medium Impact BES Cyber Systems	<p>No later than 60 calendar days after a change to the roles or responsibilities, Cyber Security Incident response groups or individuals, or technology that the Responsible Entity determines would impact the ability to execute the plan:</p> <p>3.2.1. Update the Cyber Security Incident response plan(s); and</p> <p>3.2.2. Notify each person or group with a defined role in the Cyber Security Incident response plan of the updates.</p>	<p>An example of evidence may include, but is not limited to:</p> <ol style="list-style-type: none"> 1. Dated and revised Cyber Security Incident response plan with changes to the roles or responsibilities, responders or technology; and 2. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long Term Planning	Lower	N/A	N/A	<p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include the roles and responsibilities of Cyber Security Incident response groups or individuals. (1.3)</p> <p>OR</p> <p>The Responsible Entity has developed the Cyber Security Incident response plan(s), but the plan does not include incident handling procedures for Cyber Security Incidents. (1.4)</p>	<p>The Responsible Entity has not developed a Cyber Security Incident response plan with one or more processes to identify, classify, and respond to Cyber Security Incidents. (1.1)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but the plan does not include one or more processes to identify Reportable Cyber Security Incidents. (1.2)</p> <p>OR</p> <p>The Responsible Entity has developed a Cyber Security Incident response plan, but did</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						not provide at least preliminary notification to ES-ISAC within one hour from identification of a Reportable Cyber Security Incident. (1.2)
R2	Operations Planning Real-time Operations	Lower	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 15 calendar months, not exceeding 16 calendar months between tests of the plan. (2.1)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan. (2.1)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 17 calendar months, not exceeding 18 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not document deviations, if any, from the plan during a test or when a Reportable Cyber Security Incident occurs. (2.2)	The Responsible Entity has not tested the Cyber Security Incident response plan(s) within 19 calendar months between tests of the plan. (2.1) OR The Responsible Entity did not retain relevant records related to Reportable Cyber Security Incidents. (2.3)
R3	Operations Assessment	Lower	The Responsible Entity has not notified each person or group with	The Responsible Entity has not updated the	The Responsible Entity has neither	The Responsible Entity has neither

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within greater than 90 but less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)</p>	<p>Cyber Security Incident response plan based on any documented lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not notified each person or group with a defined role in the Cyber Security Incident response plan of updates to the Cyber Security Incident response plan within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.3)</p> <p>OR</p>	<p>documented lessons learned nor documented the absence of any lessons learned within 90 and less than 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)</p> <p>OR</p> <p>The Responsible Entity has not updated the Cyber Security Incident response plan based on any documented lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not updated the</p>	<p>documented lessons learned nor documented the absence of any lessons learned within 120 calendar days of a test or actual incident response to a Reportable Cyber Security Incident. (3.1.1)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-008-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>The Responsible Entity has not updated the Cyber Security Incident response plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes. 	<p>Cyber Security Incident response plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or • Cyber Security Incident response groups or individuals, or • Technology changes. 	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The following guidelines are available to assist in addressing the required components of a Cyber Security Incident response plan:

- Department of Homeland Security, Control Systems Security Program, *Developing an Industrial Control Systems Cyber Security Incident Response Capability*, 2009, online at http://www.us-cert.gov/control_systems/practices/documents/final-RP_ics_cybersecurity_incident_response_100609.pdf
- National Institute of Standards and Technology, *Computer Security Incident Handling Guide*, Special Publication 800-61 revision 1, March 2008, online at <http://csrc.nist.gov/publications/nistpubs/800-61-rev1/SP800-61rev1.pdf>

For Part 1.2, a Reportable Cyber Security Incident is a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity. It is helpful to distinguish Reportable Cyber Security Incidents as one resulting in a necessary response action. A response action can fall into one of two categories: Necessary or elective. The distinguishing characteristic is whether or not action was taken in response to an event. Precautionary measures that are not in response to any persistent damage or effects may be designated as elective. All other response actions to avoid any persistent damage or adverse effects, which include the activation of redundant systems, should be designated as necessary.

The reporting obligations for Reportable Cyber Security Incidents require at least a preliminary notice to the ES-ISAC within one hour after determining that a Cyber Security Incident is reportable (not within one hour of the Cyber Security Incident, an important distinction). This addition is in response to the directive addressing this issue in FERC Order No. 706, paragraphs 673 and 676, to report within one hour (at least preliminarily). This standard does not require a complete report within an hour of determining that a Cyber Security Incident is reportable, but at least preliminary notice, which may be a phone call, an email, or sending a Web-based notice. The standard does not require a specific timeframe for completing the full report.

Requirement R2:

Requirement R2 ensures entities periodically test the Cyber Security Incident response plan. This includes the requirement in Part 2.2 to ensure the plan is actually used when testing. The testing requirements are specifically for *Reportable Cyber Security Incidents*.

Entities may use an actual response to a *Reportable Cyber Security Incident* as a substitute for exercising the plan annually. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or full operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, “A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. Table top exercises (TTX) can be used to assess plans, policies, and procedures.”

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, “[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and ‘boots on the ground’ response (e.g., firefighters decontaminating mock victims).”

In addition to the requirements to implement the response plan, Part 2.3 specifies entities must retain relevant records for *Reportable Cyber Security Incidents*. There are several examples of specific types of evidence listed in the measure. Entities should refer to their handling procedures to determine the types of evidence to retain and how to transport and store the evidence. For further information in retaining incident records, refer to the NIST Guide to Integrating Forensic Techniques into Incident Response (SP800-86). The NIST guideline includes a section (Section 3.1.2) on acquiring data when performing forensics.

Requirement R3:

This requirement ensures entities maintain Cyber Security Incident response plans. There are two requirement parts that trigger plan updates: (1) lessons learned from Part 3.1 and (2) organizational or technology changes from Part 3.2.

The documentation of lessons learned from Part 3.1 is associated with each Reportable Cyber Security Incident and involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the incident in recognition that complex incidents on complex systems can take a few days or weeks to complete response

activities. The process of conducting lessons learned can involve the response team discussing the incident to determine gaps or areas of improvement within the plan. Any documented deviations from the plan from Part 2.2 can serve as input to the lessons learned. It is possible to have a *Reportable Cyber Security Incident* without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the *Reportable Cyber Security Incident*.

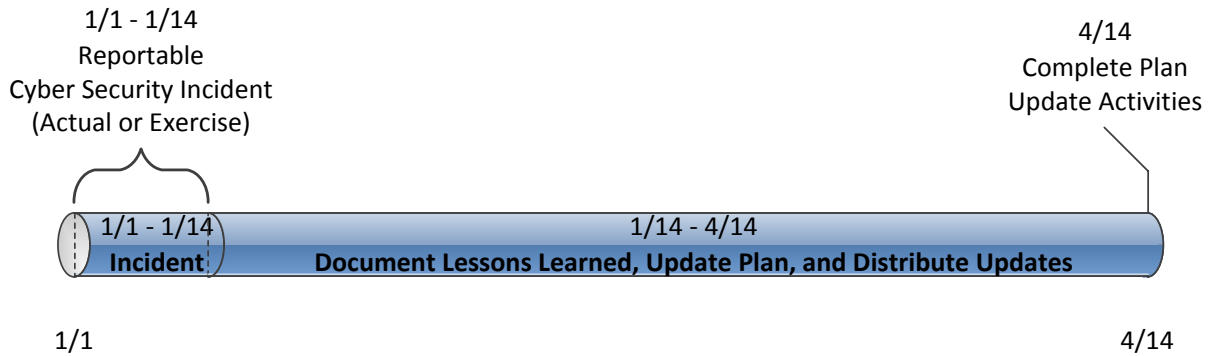


Figure 1: CIP-008-5(X) R3 Timeline for Reportable Cyber Security Incidents

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the incident and documenting the lessons learned as soon after the incident as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the incident response team.

The plan change requirement in Part 3.2 is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems or ticketing systems.

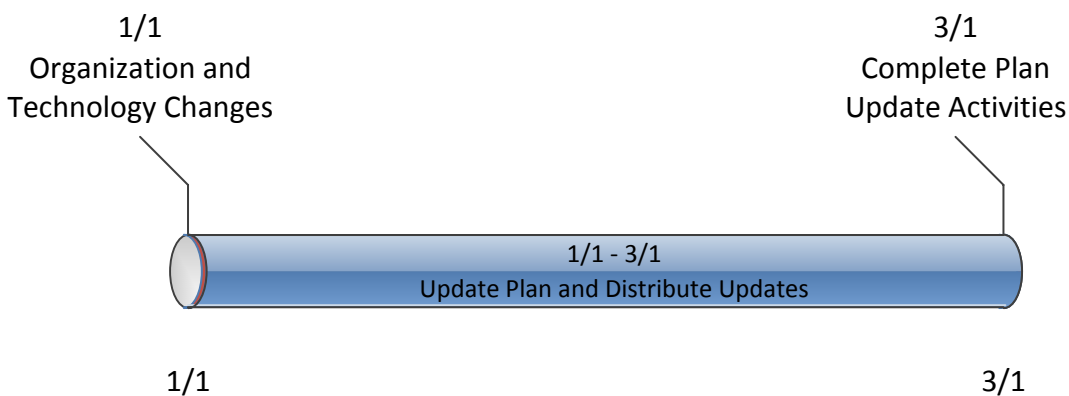


Figure 2: Timeline for Plan Changes in 3.2

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned incident response capability is therefore necessary for rapidly detecting incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services. An enterprise or single incident response plan for all BES Cyber Systems may be used to meet the Requirement. An organization may have a common plan for multiple registered entities it owns.

Summary of Changes: Wording changes have been incorporated based primarily on industry feedback to more specifically describe required actions.

Reference to prior version: (Part 1.1) CIP-008, R1.1

Change Description and Justification: (Part 1.1)

“Characterize” has been changed to “identify” for clarity. “Response actions” has been changed to “respond to” for clarity.

Reference to prior version: (Part 1.2) CIP-008, R1.1

Change Description and Justification: (Part 1.2)

Addresses the reporting requirements from previous versions of CIP-008. This requirement part only obligates entities to have a process for determining Reportable Cyber Security Incidents. Also addresses the directive in FERC Order No. 706, paragraphs 673 and 676 to report within one hour (at least preliminarily).

Reference to prior version: (Part 1.3) CIP-008, R1.2

Change Description and Justification: (Part 1.3)

Replaced incident response teams with incident response “groups or individuals” to avoid the interpretation that roles and responsibilities sections must reference specific teams.

Reference to prior version: (Part 1.4) CIP-008, R1.2

Change Description and Justification: (Part 1.4)

Conforming change to reference new defined term Cyber Security Incidents.

Rationale for R2:

The implementation of an effective Cyber Security Incident response plan mitigates the risk to the reliable operation of the BES caused as the result of a Cyber Security Incident and provides feedback to Responsible Entities for improving the security controls applying to BES Cyber Systems. This requirement ensures implementation of the response plans. Requirement Part 2.3 ensures the retention of incident documentation for post event analysis.

This requirement obligates entities to follow the Cyber Security Incident response plan when an incident occurs or when testing, but does not restrict entities from taking needed deviations from the plan. It ensures the plan represents the actual response and does not exist for documentation only. If a plan is written at a high enough level, then every action during the response should not be subject to scrutiny. The plan will likely allow for the appropriate variance in tactical decisions made by incident responders. Deviations from the plan can be documented during the incident response or afterward as part of the review.

Summary of Changes: Added testing requirements to verify the Responsible Entity’s response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System.

Reference to prior version: (Part 2.1) CIP-008, R1.6

Change Description and Justification: (Part 2.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-008, R1.6

Change Description and Justification: (Part 2.2)

Allows deviation from plan(s) during actual events or testing if deviations are recorded for review.

Reference to prior version: (Part 2.3) CIP-008, R2

Change Description and Justification: (Part 2.3)

Removed references to the retention period because the Standard addresses data retention in the Compliance Section.

Rationale for R3:

Conduct sufficient reviews, updates and communications to verify the Responsible Entity’s response plan’s effectiveness and consistent application in responding to a Cyber Security Incident(s) impacting a BES Cyber System. A separate plan is not required for those requirement parts of the table applicable to High or Medium Impact BES Cyber Systems. If an entity has a single Cyber Security Incident response plan and High or Medium Impact BES Cyber Systems, then the additional requirements would apply to the single plan.

Summary of Changes: Changes here address the FERC Order 706, Paragraph 686, which includes a directive to perform after-action review for tests or actual incidents and update the

plan based on lessons learned. Additional changes include specification of what it means to review the plan and specification of changes that would require an update to the plan.

Reference to prior version: (Part 3.1) CIP-008, R1.5

Change Description and Justification: (Part 3.1)

Addresses FERC Order 706, Paragraph 686 to document test or actual incidents and lessons learned.

Reference to prior version: (Part 3.2) CIP-008, R1.4

Change Description and Justification: (Part 3.2)

Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the changes that would require an update.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center.”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3		Updated version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	

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4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-008-5. (Order becomes effective on 2/3/14.)	
<u>5(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — Recovery Plans for BES Cyber Systems
2. **Number:** CIP-009-5(X)
3. **Purpose:** To recover reliability functions performed by BES Cyber Systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**
 - 4.1.7 **Transmission Operator**

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-009-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-009-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-009-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-009-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding

paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to BES Cyber Systems located at a Control Center and categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples include, but are not limited to firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

B. Requirements and Measures

- R1.** Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning].
- M1.** Evidence must include the documented recovery plan(s) that collectively include the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*.

CIP-009-5(X) Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	Conditions for activation of the recovery plan(s).	An example of evidence may include, but is not limited to, one or more plans that include language identifying conditions for activation of the recovery plan(s).

CIP-009-5(X) Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	Roles and responsibilities of responders.	An example of evidence may include, but is not limited to, one or more recovery plans that include language identifying the roles and responsibilities of responders.
1.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	One or more processes for the backup and storage of information required to recover BES Cyber System functionality.	An example of evidence may include, but is not limited to, documentation of specific processes for the backup and storage of information required to recover BES Cyber System functionality.

CIP-009-5(X) Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>One or more processes to verify the successful completion of the backup processes in Part 1.3 and to address any backup failures.</p>	<p>An example of evidence may include, but is not limited to, logs, workflow or other documentation confirming that the backup process completed successfully and backup failures, if any, were addressed.</p>
1.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>One or more processes to preserve data, per Cyber Asset capability, for determining the cause of a Cyber Security Incident that triggers activation of the recovery plan(s). Data preservation should not impede or restrict recovery.</p>	<p>An example of evidence may include, but is not limited to, procedures to preserve data, such as preserving a corrupted drive or making a data mirror of the system before proceeding with recovery.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-time Operations.]
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*.

CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Test each of the recovery plans referenced in Requirement R1 at least once every 15 calendar months:</p> <ul style="list-style-type: none"> • By recovering from an actual incident; • With a paper drill or tabletop exercise; or • With an operational exercise. 	<p>An example of evidence may include, but is not limited to, dated evidence of a test (by recovering from an actual incident, with a paper drill or tabletop exercise, or with an operational exercise) of the recovery plan at least once every 15 calendar months. For the paper drill or full operational exercise, evidence may include meeting notices, minutes, or other records of exercise findings.</p>

CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Test a representative sample of information used to recover BES Cyber System functionality at least once every 15 calendar months to ensure that the information is useable and is compatible with current configurations.</p> <p>An actual recovery that incorporates the information used to recover BES Cyber System functionality substitutes for this test.</p>	<p>An example of evidence may include, but is not limited to, operational logs or test results with criteria for testing the usability (e.g. sample tape load, browsing tape contents) and compatibility with current system configurations (e.g. manual or automated comparison checkpoints between backup media contents and current configuration).</p>
2.3	High Impact BES Cyber Systems	<p>Test each of the recovery plans referenced in Requirement R1 at least once every 36 calendar months through an operational exercise of the recovery plans in an environment representative of the production environment.</p> <p>An actual recovery response may substitute for an operational exercise.</p>	<p>Examples of evidence may include, but are not limited to, dated documentation of:</p> <ul style="list-style-type: none"> • An operational exercise at least once every 36 calendar months between exercises, that demonstrates recovery in a representative environment; or • An actual recovery response that occurred within the 36 calendar month timeframe that exercised the recovery plans.

- R3.** Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable requirement parts in *CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication*. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].
- M3.** Acceptable evidence includes, but is not limited to, each of the applicable requirement parts in *CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication*.

CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication			
Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>No later than 90 calendar days after completion of a recovery plan test or actual recovery:</p> <ol style="list-style-type: none"> 3.1.1. Document any lessons learned associated with a recovery plan test or actual recovery or document the absence of any lessons learned; 3.1.2. Update the recovery plan based on any documented lessons learned associated with the plan; and 3.1.3. Notify each person or group with a defined role in the recovery plan of the updates to the recovery plan based on any documented lessons learned. 	<p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> 1. Dated documentation of identified deficiencies or lessons learned for each recovery plan test or actual incident recovery or dated documentation stating there were no lessons learned; 2. Dated and revised recovery plan showing any changes based on the lessons learned; and 3. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication			
Part	Applicable Systems	Requirements	Measures
3.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>No later than 60 calendar days after a change to the roles or responsibilities, responders, or technology that the Responsible Entity determines would impact the ability to execute the recovery plan:</p> <ol style="list-style-type: none"> 3.2.1. Update the recovery plan; and 3.2.2. Notify each person or group with a defined role in the recovery plan of the updates. 	<p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> 1. Dated and revised recovery plan with changes to the roles or responsibilities, responders, or technology; and 2. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	The Responsible Entity has developed recovery plan(s), but the plan(s) do not address one of the requirements included in Parts 1.2 through 1.5.	The Responsible Entity has developed recovery plan(s), but the plan(s) do not address two of the requirements included in Parts 1.2 through 1.5.	The Responsible Entity has not created recovery plan(s) for BES Cyber Systems. OR The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address the conditions for activation in Part 1.1. OR The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address three or more of the requirements in Parts 1.2 through 1.5.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning Real-time Operations	Lower	<p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 15 calendar months, not exceeding 16 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 15 calendar months, not exceeding 16 calendar months between tests, and</p>	<p>The Responsible Entity has not tested the recovery plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 16 calendar months, not exceeding 17 calendar months between tests, and when tested, any</p>	<p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 17 calendar months, not exceeding 18 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 17 calendar months, not exceeding 18 calendar months between tests, and</p>	<p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 18 calendar months between tests of the plan. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 and identified deficiencies, but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 but did not identify, assess, or correct the deficiencies. (2.1)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>when tested, any deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 36 calendar months, not exceeding 37 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p>	<p>deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 37 calendar months, not exceeding 38 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p>	<p>when tested, any deficiencies were identified, assessed, and corrected. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 38 calendar months, not exceeding 39 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)</p>	<p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 18 calendar months between tests. (2.2)</p> <p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 and identified deficiencies, but did not assess or correct the deficiencies. (2.2)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						<p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.3 within 39 calendar months between tests of the plan. (2.3)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						2.3 and identified deficiencies, but did not assess or correct the deficiencies. (2.3) OR The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.3 but did not identify, assess, or correct the deficiencies. (2.3)
R3	Operations Assessment	Lower	The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 90 and less than 210 calendar days of the update being completed. (3.1.3)	The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.2) OR	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.1)	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 210 calendar days of each recovery plan test or actual recovery. (3.1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 120 calendar days of the update being completed. (3.1.3)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or • Responders, or 	<p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 120 calendar days of each recovery plan test or actual recovery. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or 	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<ul style="list-style-type: none"> • Technology changes. 	<ul style="list-style-type: none"> • Responders, or Technology changes. 	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The following guidelines are available to assist in addressing the required components of a recovery plan:

- NERC, Security Guideline for the Electricity Sector: Continuity of Business Processes and Operations Operational Functions, September 2011, online at <http://www.nerc.com/docs/cip/sgwg/Continuity%20of%20Business%20and%20Operational%20Functions%20FINAL%20102511.pdf>
- National Institute of Standards and Technology, Contingency Planning Guide for Federal Information Systems, Special Publication 800-34 revision 1, May 2010, online at http://csrc.nist.gov/publications/nistpubs/800-34-rev1/sp800-34-rev1_errata-Nov11-2010.pdf

The term recovery plan is used throughout this Standard to refer to a documented set of instructions and resources needed to recover reliability functions performed by BES Cyber Systems. The recovery plan may exist as part of a larger business continuity or disaster recovery plan, but the term does not imply any additional obligations associated with those disciplines outside of the Requirements.

A documented recovery plan may not be necessary for each applicable BES Cyber System. For example, the short-term recovery plan for a BES Cyber System in a specific substation may be

managed on a daily basis by advanced power system applications such as state estimation, contingency and remedial action, and outage scheduling. One recovery plan for BES Cyber Systems should suffice for several similar facilities such as those found in substations or power plants' facilities.

For Part 1.1, the conditions for activation of the recovery plan should consider viable threats to the BES Cyber System such as natural disasters, computing equipment failures, computing environment failures, and Cyber Security Incidents. A business impact analysis for the BES Cyber System may be useful in determining these conditions.

For Part 1.2, entities should identify the individuals required for responding to a recovery operation of the applicable BES Cyber System.

For Part 1.3, entities should consider the following types of information to recover BES Cyber System functionality:

1. Installation files and media;
2. Current backup tapes and any additional documented configuration settings;
3. Documented build or restoration procedures; and
4. Cross site replication storage.

For Part 1.4, the processes to verify the successful completion of backup processes should include checking for: (1) usability of backup media, (2) logs or inspection showing that information from current, production system could be read, and (3) logs or inspection showing that information was written to the backup media. Test restorations are not required for this Requirement Part. The following backup scenarios provide examples of effective processes to verify successful completion and detect any backup failures:

- Periodic (e.g. daily or weekly) backup process – Review generated logs or job status reports and set up notifications for backup failures.
- Non-periodic backup process– If a single backup is provided during the commissioning of the system, then only the initial and periodic (every 15 months) testing must be done. Additional testing should be done as necessary and can be a part of the configuration change management program.
- Data mirroring – Configure alerts on the failure of data transfer for an amount of time specified by the entity (e.g. 15 minutes) in which the information on the mirrored disk may no longer be useful for recovery.
- Manual configuration information – Inspect the information used for recovery prior to storing initially and periodically (every 15 months). Additional inspection should be done as necessary and can be a part of the configuration change management program.

The plan must also include processes to address backup failures. These processes should specify the response to failure notifications or other forms of identification.

For Part 1.5, the recovery plan must include considerations for preservation of data to determine the cause of a Cyber Security Incident. Because it is not always possible to initially

know if a Cyber Security Incident caused the recovery activation, the data preservation procedures should be followed until such point a Cyber Security Incident can be ruled out. CIP-008 addresses the retention of data associated with a Cyber Security Incident.

Requirement R2:

A Responsible Entity must exercise each BES Cyber System recovery plan every 15 months. However, this does not necessarily mean that the entity must test each plan individually. BES Cyber Systems that are numerous and distributed, such as those found at substations, may not require an individual recovery plan and the associated redundant facilities since reengineering and reconstruction may be the generic response to a severe event. Conversely, there is typically one control center per bulk transmission service area that requires a redundant or backup facility. Because of these differences, the recovery plans associated with control centers differ a great deal from those associated with power plants and substations.

A recovery plan test does not necessarily cover all aspects of a recovery plan and failure scenarios, but the test should be sufficient to ensure the plan is up to date and at least one restoration process of the applicable cyber systems is covered.

Entities may use an actual recovery as a substitute for exercising the plan every 15 months. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. [Table top exercises (TTX)] can be used to assess plans, policies, and procedures."

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."

For Part 2.2, entities should refer to the backup and storage of information required to recover BES Cyber System functionality in Requirement Part 1.3. This provides additional assurance that the information will actually recover the BES Cyber System as necessary. For most complex computing equipment, a full test of the information is not feasible. Entities should determine the representative sample of information that provides assurance in the processes for Requirement Part 1.3. The test must include steps for ensuring the information is useable and current. For backup media, this can include testing a representative sample to make sure the information can be loaded, and checking the content to make sure the information reflects the current configuration of the applicable Cyber Assets.

Requirement R3:

This requirement ensures entities maintain recovery plans. There are two requirement parts that trigger plan updates: (1) lessons learned and (2) organizational or technology changes.

The documentation of lessons learned is associated with each recovery activation, and it involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the recovery operation in recognition that complex recovery activities can take a few days or weeks to complete. The process of conducting lessons learned can involve the recovery team discussing the incident to determine gaps or areas of improvement within the plan. It is possible to have a recovery activation without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the recovery activation.

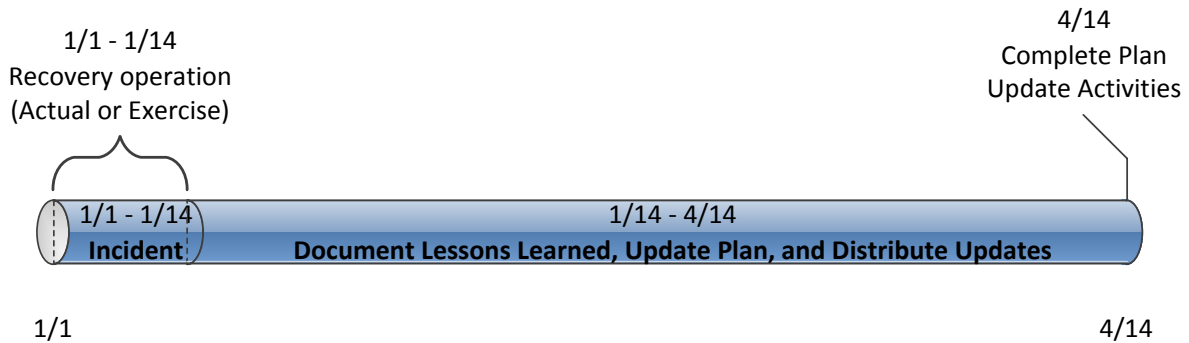


Figure 1: CIP-009-5(X) R3 Timeline

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the recovery and documenting the lessons learned as soon after the recovery activation as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the recovery team.

The plan change requirement is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems, or ticketing systems.

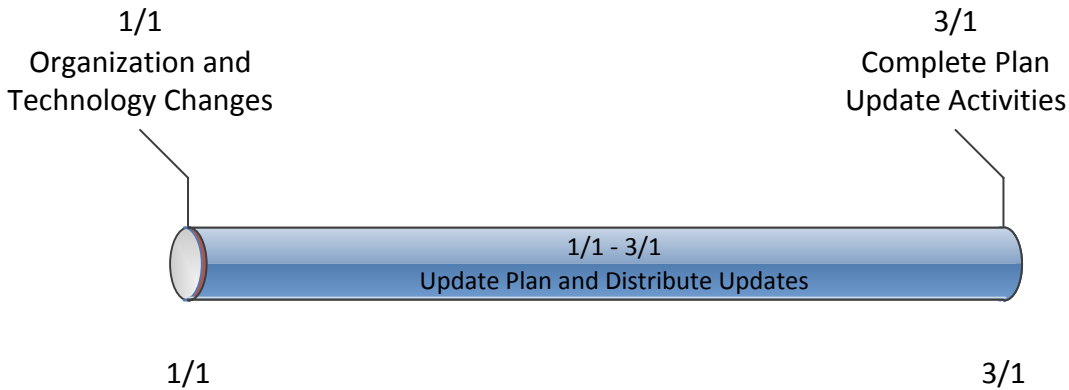


Figure 2: Timeline for Plan Changes in 3.2

When notifying individuals of response plan changes, entities should keep in mind that recovery plans may be considered BES Cyber System Information, and they should take the appropriate measures to prevent unauthorized disclosure of recovery plan information. For example, the recovery plan itself, or other sensitive information about the recovery plan, should be redacted from Email or other unencrypted transmission.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned recovery capability is, therefore, necessary for rapidly recovering from incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services so that planned and consistent recovery action to restore BES Cyber System functionality occurs.

Summary of Changes: Added provisions to protect data that would be useful in the investigation of an event that results in the need for a Cyber System recovery plan to be utilized.

Reference to prior version: (Part 1.1) CIP-009, R1.1

Change Description and Justification: (Part 1.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 1.2) CIP-009, R1.2

Change Description and Justification: (Part 1.2)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 1.3) CIP-009, R4

Change Description and Justification: (Part 1.3)

Addresses FERC Order Paragraph 739 and 748. The modified wording was abstracted from Paragraph 744.

Reference to prior version: (Part 1.4) New Requirement

Change Description and Justification: (Part 1.4)

Addresses FERC Order Section 739 and 748.

Reference to prior version: (Part 1.5) New Requirement

Change Description and Justification: (Part 1.5)

Added requirement to address FERC Order No. 706, Paragraph 706.

Rationale for R2:

The implementation of an effective recovery plan mitigates the risk to the reliable operation of the BES by reducing the time to recover from various hazards affecting BES Cyber Systems. This requirement ensures continued implementation of the response plans.

Requirement Part 2.2 provides further assurance in the information (e.g. backup tapes, mirrored hot-sites, etc.) necessary to recover BES Cyber Systems. A full test is not feasible in most instances due to the amount of recovery information, and the Responsible Entity must determine a sampling that provides assurance in the usability of the information.

Summary of Changes. Added operational testing for recovery of BES Cyber Systems.

Reference to prior version: (Part 2.1) CIP-009, R2

Change Description and Justification: (Part 2.1)

Minor wording change; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-009, R5

Change Description and Justification: (Part 2.2)

Specifies what to test and makes clear the test can be a representative sampling. These changes, along with Requirement Part 1.4 address the FERC Order No. 706, Paragraphs 739 and 748 related to testing of backups by providing high confidence the information will actually recover the system as necessary.

Reference to prior version: (Part 2.3) CIP-009, R2

Change Description and Justification: (Part 2.3)

Addresses FERC Order No. 706, Paragraph 725 to add the requirement that the recovery plan test be a full operational test once every 3 years.

Rationale for R3:

To improve the effectiveness of BES Cyber System recovery plan(s) following a test, and to ensure the maintenance and distribution of the recovery plan(s). Responsible Entities achieve this by (i) performing a lessons learned review in 3.1 and (ii) revising the plan in 3.2 based on specific changes in the organization or technology that would impact plan execution. In both instances when the plan needs to change, the Responsible Entity updates and distributes the plan.

Summary of Changes: Makes clear when to perform lessons learned review of the plan and specifies the timeframe for updating the recovery plan.

Reference to prior version: (Part 3.1) CIP-009, R1 and R3

Change Description and Justification: (Part 3.1)

Added the timeframes for performing lessons learned and completing the plan updates. This requirement combines all three activities in one place. Where previous versions specified 30 calendar days for performing lessons learned, followed by additional time for updating recovery plans and notification, this requirement combines those activities into a single timeframe.

Reference to prior version: (Part 3.2) New Requirement

Change Description and Justification: (Part 3.2)

Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the specific changes that would require an update.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	

Guidelines and Technical Basis

3		Updated version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-009-5. (Order becomes effective on 2/3/14.)	
5(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — Recovery Plans for BES Cyber Systems
2. **Number:** CIP-009-5(X)
3. **Purpose:** To recover reliability functions performed by BES Cyber Systems by specifying recovery plan requirements in support of the continued stability, operability, and reliability of the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-009-5(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-009-5(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-009-5(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-009-5(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to BES Cyber Systems located at a Control Center and categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples include, but are not limited to firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.

B. Requirements and Measures

- R1.** Each Responsible Entity shall have one or more documented recovery plans that collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning].
- M1.** Evidence must include the documented recovery plan(s) that collectively include the applicable requirement parts in *CIP-009-5(X) Table R1 – Recovery Plan Specifications*.

CIP-009-5(X) Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.1	High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	Conditions for activation of the recovery plan(s).	An example of evidence may include, but is not limited to, one or more plans that include language identifying conditions for activation of the recovery plan(s).

CIP-009-5(X) Table R1 – Recovery Plan Specifications

Part	Applicable Systems	Requirements	Measures
1.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Roles and responsibilities of responders.</p>	<p>An example of evidence may include, but is not limited to, one or more recovery plans that include language identifying the roles and responsibilities of responders.</p>
1.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>One or more processes for the backup and storage of information required to recover BES Cyber System functionality.</p>	<p>An example of evidence may include, but is not limited to, documentation of specific processes for the backup and storage of information required to recover BES Cyber System functionality.</p>

CIP-009-5(X) Table R1 – Recovery Plan Specifications			
Part	Applicable Systems	Requirements	Measures
1.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>One or more processes to verify the successful completion of the backup processes in Part 1.3 and to address any backup failures.</p>	<p>An example of evidence may include, but is not limited to, logs, workflow or other documentation confirming that the backup process completed successfully and backup failures, if any, were addressed.</p>
1.5	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>One or more processes to preserve data, per Cyber Asset capability, for determining the cause of a Cyber Security Incident that triggers activation of the recovery plan(s). Data preservation should not impede or restrict recovery.</p>	<p>An example of evidence may include, but is not limited to, procedures to preserve data, such as preserving a corrupted drive or making a data mirror of the system before proceeding with recovery.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, its documented recovery plan(s) to collectively include each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning and Real-time Operations.]
- M2.** Evidence must include, but is not limited to, documentation that collectively demonstrates implementation of each of the applicable requirement parts in *CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing*.

CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Test each of the recovery plans referenced in Requirement R1 at least once every 15 calendar months:</p> <ul style="list-style-type: none"> • By recovering from an actual incident; • With a paper drill or tabletop exercise; or • With an operational exercise. 	<p>An example of evidence may include, but is not limited to, dated evidence of a test (by recovering from an actual incident, with a paper drill or tabletop exercise, or with an operational exercise) of the recovery plan at least once every 15 calendar months. For the paper drill or full operational exercise, evidence may include meeting notices, minutes, or other records of exercise findings.</p>

CIP-009-5(X) Table R2 – Recovery Plan Implementation and Testing			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Test a representative sample of information used to recover BES Cyber System functionality at least once every 15 calendar months to ensure that the information is useable and is compatible with current configurations.</p> <p>An actual recovery that incorporates the information used to recover BES Cyber System functionality substitutes for this test.</p>	<p>An example of evidence may include, but is not limited to, operational logs or test results with criteria for testing the usability (e.g. sample tape load, browsing tape contents) and compatibility with current system configurations (e.g. manual or automated comparison checkpoints between backup media contents and current configuration).</p>
2.3	High Impact BES Cyber Systems	<p>Test each of the recovery plans referenced in Requirement R1 at least once every 36 calendar months through an operational exercise of the recovery plans in an environment representative of the production environment.</p> <p>An actual recovery response may substitute for an operational exercise.</p>	<p>Examples of evidence may include, but are not limited to, dated documentation of:</p> <ul style="list-style-type: none"> • An operational exercise at least once every 36 calendar months between exercises, that demonstrates recovery in a representative environment; or • An actual recovery response that occurred within the 36 calendar month timeframe that exercised the recovery plans.

R3. Each Responsible Entity shall maintain each of its recovery plans in accordance with each of the applicable requirement parts in CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication. [Violation Risk Factor: Lower] [Time Horizon: Operations Assessment].

M3. Acceptable evidence includes, but is not limited to, each of the applicable requirement parts in CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication.

CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication			
Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>No later than 90 calendar days after completion of a recovery plan test or actual recovery:</p> <ol style="list-style-type: none"> 3.1.1. Document any lessons learned associated with a recovery plan test or actual recovery or document the absence of any lessons learned; 3.1.2. Update the recovery plan based on any documented lessons learned associated with the plan; and 3.1.3. Notify each person or group with a defined role in the recovery plan of the updates to the recovery plan based on any documented lessons learned. 	<p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> 1. Dated documentation of identified deficiencies or lessons learned for each recovery plan test or actual incident recovery or dated documentation stating there were no lessons learned; 2. Dated and revised recovery plan showing any changes based on the lessons learned; and 3. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

CIP-009-5(X) Table R3 – Recovery Plan Review, Update and Communication			
Part	Applicable Systems	Requirements	Measures
3.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems at Control Centers and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>No later than 60 calendar days after a change to the roles or responsibilities, responders, or technology that the Responsible Entity determines would impact the ability to execute the recovery plan:</p> <ol style="list-style-type: none"> 3.2.1. Update the recovery plan; and 3.2.2. Notify each person or group with a defined role in the recovery plan of the updates. 	<p>An example of evidence may include, but is not limited to, all of the following:</p> <ol style="list-style-type: none"> 1. Dated and revised recovery plan with changes to the roles or responsibilities, responders, or technology; and 2. Evidence of plan update distribution including, but not limited to: <ul style="list-style-type: none"> • Emails; • USPS or other mail service; • Electronic distribution system; or • Training sign-in sheets.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	N/A	The Responsible Entity has developed recovery plan(s), but the plan(s) do not address one of the requirements included in Parts 1.2 through 1.5.	The Responsible Entity has developed recovery plan(s), but the plan(s) do not address two of the requirements included in Parts 1.2 through 1.5.	The Responsible Entity has not created recovery plan(s) for BES Cyber Systems. OR The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address the conditions for activation in Part 1.1. OR The Responsible Entity has created recovery plan(s) for BES Cyber Systems, but the plan(s) does not address three or more of the requirements in Parts 1.2 through 1.5.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Planning Real-time Operations	Lower	<p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 15 calendar months, not exceeding 16 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 15 calendar months, not exceeding 16 calendar months between tests, and</p>	<p>The Responsible Entity has not tested the recovery plan(s) within 16 calendar months, not exceeding 17 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 16 calendar months, not exceeding 17 calendar months between tests, and when tested, any</p>	<p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 17 calendar months, not exceeding 18 calendar months between tests of the plan, and when tested, any deficiencies were identified, assessed, and corrected. (2.1)</p> <p>OR</p> <p>The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 17 calendar months, not exceeding 18 calendar months between tests, and</p>	<p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.1 within 18 calendar months between tests of the plan. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 and identified deficiencies, but did not assess or correct the deficiencies. (2.1)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.1 but did not identify, assess, or correct the deficiencies. (2.1)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			when tested, any deficiencies were identified, assessed, and corrected. (2.2) OR The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 36 calendar months, not exceeding 37 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)	deficiencies were identified, assessed, and corrected. (2.2) OR The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 37 calendar months, not exceeding 38 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)	when tested, any deficiencies were identified, assessed, and corrected. (2.2) OR The Responsible Entity has not tested the recovery plan according to R2 Part 2.3 within 38 calendar months, not exceeding 39 calendar months between tests, and when tested, any deficiencies were identified, assessed, and corrected. (2.3)	OR The Responsible Entity has not tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 within 18 calendar months between tests. (2.2) OR The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 and identified deficiencies, but did not assess or correct the deficiencies. (2.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						<p>OR</p> <p>The Responsible Entity has tested a representative sample of the information used in the recovery of BES Cyber System functionality according to R2 Part 2.2 but did not identify, assess, or correct the deficiencies. (2.2)</p> <p>OR</p> <p>The Responsible Entity has not tested the recovery plan(s) according to R2 Part 2.3 within 39 calendar months between tests of the plan. (2.3)</p> <p>OR</p> <p>The Responsible Entity has tested the recovery plan(s) according to R2 Part</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						2.3 and identified deficiencies, but did not assess or correct the deficiencies. (2.3) OR The Responsible Entity has tested the recovery plan(s) according to R2 Part 2.3 but did not identify, assess, or correct the deficiencies. (2.3)
R3	Operations Assessment	Lower	The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 90 and less than 210 calendar days of the update being completed. (3.1.3)	The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.2) OR	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 90 and less than 210 calendar days of each recovery plan test or actual recovery. (3.1.1)	The Responsible Entity has neither documented lessons learned nor documented the absence of any lessons learned within 210 calendar days of each recovery plan test or actual recovery. (3.1.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>The Responsible Entity has not notified each person or group with a defined role in the recovery plan(s) of updates within 120 calendar days of the update being completed. (3.1.3)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 60 and less than 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or • Responders, or 	<p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) based on any documented lessons learned within 120 calendar days of each recovery plan test or actual recovery. (3.1.2)</p> <p>OR</p> <p>The Responsible Entity has not updated the recovery plan(s) or notified each person or group with a defined role within 90 calendar days of any of the following changes that the responsible entity determines would impact the ability to execute the plan: (3.2)</p> <ul style="list-style-type: none"> • Roles or responsibilities, or 	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-009-5(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				<ul style="list-style-type: none"> • Technology changes. 	<ul style="list-style-type: none"> • Responders, or Technology changes. 	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

The following guidelines are available to assist in addressing the required components of a recovery plan:

- NERC, Security Guideline for the Electricity Sector: Continuity of Business Processes and Operations Operational Functions, September 2011, online at <http://www.nerc.com/docs/cip/sgwg/Continuity%20of%20Business%20and%20Operational%20Functions%20FINAL%20102511.pdf>
- National Institute of Standards and Technology, Contingency Planning Guide for Federal Information Systems, Special Publication 800-34 revision 1, May 2010, online at http://csrc.nist.gov/publications/nistpubs/800-34-rev1/sp800-34-rev1_errata-Nov11-2010.pdf

The term recovery plan is used throughout this Standard to refer to a documented set of instructions and resources needed to recover reliability functions performed by BES Cyber Systems. The recovery plan may exist as part of a larger business continuity or disaster recovery plan, but the term does not imply any additional obligations associated with those disciplines outside of the Requirements.

A documented recovery plan may not be necessary for each applicable BES Cyber System. For example, the short-term recovery plan for a BES Cyber System in a specific substation may be

managed on a daily basis by advanced power system applications such as state estimation, contingency and remedial action, and outage scheduling. One recovery plan for BES Cyber Systems should suffice for several similar facilities such as those found in substations or power plants' facilities.

For Part 1.1, the conditions for activation of the recovery plan should consider viable threats to the BES Cyber System such as natural disasters, computing equipment failures, computing environment failures, and Cyber Security Incidents. A business impact analysis for the BES Cyber System may be useful in determining these conditions.

For Part 1.2, entities should identify the individuals required for responding to a recovery operation of the applicable BES Cyber System.

For Part 1.3, entities should consider the following types of information to recover BES Cyber System functionality:

1. Installation files and media;
2. Current backup tapes and any additional documented configuration settings;
3. Documented build or restoration procedures; and
4. Cross site replication storage.

For Part 1.4, the processes to verify the successful completion of backup processes should include checking for: (1) usability of backup media, (2) logs or inspection showing that information from current, production system could be read, and (3) logs or inspection showing that information was written to the backup media. Test restorations are not required for this Requirement Part. The following backup scenarios provide examples of effective processes to verify successful completion and detect any backup failures:

- Periodic (e.g. daily or weekly) backup process – Review generated logs or job status reports and set up notifications for backup failures.
- Non-periodic backup process– If a single backup is provided during the commissioning of the system, then only the initial and periodic (every 15 months) testing must be done. Additional testing should be done as necessary and can be a part of the configuration change management program.
- Data mirroring – Configure alerts on the failure of data transfer for an amount of time specified by the entity (e.g. 15 minutes) in which the information on the mirrored disk may no longer be useful for recovery.
- Manual configuration information – Inspect the information used for recovery prior to storing initially and periodically (every 15 months). Additional inspection should be done as necessary and can be a part of the configuration change management program.

The plan must also include processes to address backup failures. These processes should specify the response to failure notifications or other forms of identification.

For Part 1.5, the recovery plan must include considerations for preservation of data to determine the cause of a Cyber Security Incident. Because it is not always possible to initially

know if a Cyber Security Incident caused the recovery activation, the data preservation procedures should be followed until such point a Cyber Security Incident can be ruled out. CIP-008 addresses the retention of data associated with a Cyber Security Incident.

Requirement R2:

A Responsible Entity must exercise each BES Cyber System recovery plan every 15 months. However, this does not necessarily mean that the entity must test each plan individually. BES Cyber Systems that are numerous and distributed, such as those found at substations, may not require an individual recovery plan and the associated redundant facilities since reengineering and reconstruction may be the generic response to a severe event. Conversely, there is typically one control center per bulk transmission service area that requires a redundant or backup facility. Because of these differences, the recovery plans associated with control centers differ a great deal from those associated with power plants and substations.

A recovery plan test does not necessarily cover all aspects of a recovery plan and failure scenarios, but the test should be sufficient to ensure the plan is up to date and at least one restoration process of the applicable cyber systems is covered.

Entities may use an actual recovery as a substitute for exercising the plan every 15 months. Otherwise, entities must exercise the plan with a paper drill, tabletop exercise, or operational exercise. For more specific types of exercises, refer to the FEMA Homeland Security Exercise and Evaluation Program (HSEEP). It lists the following four types of discussion-based exercises: seminar, workshop, tabletop, and games. In particular, it defines that, "A tabletop exercise involves key personnel discussing simulated scenarios in an informal setting. [Table top exercises (TTX)] can be used to assess plans, policies, and procedures."

The HSEEP lists the following three types of operations-based exercises: Drill, functional exercise, and full-scale exercise. It defines that, "[A] full-scale exercise is a multi-agency, multi-jurisdictional, multi-discipline exercise involving functional (e.g., joint field office, Emergency operation centers, etc.) and 'boots on the ground' response (e.g., firefighters decontaminating mock victims)."

For Part 2.2, entities should refer to the backup and storage of information required to recover BES Cyber System functionality in Requirement Part 1.3. This provides additional assurance that the information will actually recover the BES Cyber System as necessary. For most complex computing equipment, a full test of the information is not feasible. Entities should determine the representative sample of information that provides assurance in the processes for Requirement Part 1.3. The test must include steps for ensuring the information is useable and current. For backup media, this can include testing a representative sample to make sure the information can be loaded, and checking the content to make sure the information reflects the current configuration of the applicable Cyber Assets.

Requirement R3:

This requirement ensures entities maintain recovery plans. There are two requirement parts that trigger plan updates: (1) lessons learned and (2) organizational or technology changes.

The documentation of lessons learned is associated with each recovery activation, and it involves the activities as illustrated in Figure 1, below. The deadline to document lessons learned starts after the completion of the recovery operation in recognition that complex recovery activities can take a few days or weeks to complete. The process of conducting lessons learned can involve the recovery team discussing the incident to determine gaps or areas of improvement within the plan. It is possible to have a recovery activation without any documented lessons learned. In such cases, the entity must retain documentation of the absence of any lessons learned associated with the recovery activation.

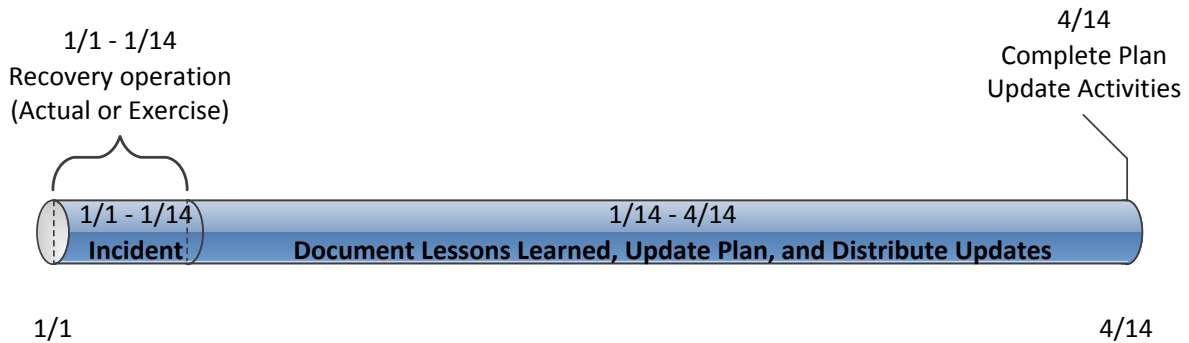


Figure 1: CIP-009-5(X) R3 Timeline

The activities necessary to complete the lessons learned include updating the plan and distributing those updates. Entities should consider meeting with all of the individuals involved in the recovery and documenting the lessons learned as soon after the recovery activation as possible. This allows more time for making effective updates to the plan, obtaining any necessary approvals, and distributing those updates to the recovery team.

The plan change requirement is associated with organization and technology changes referenced in the plan and involves the activities illustrated in Figure 2, below. Organizational changes include changes to the roles and responsibilities people have in the plan or changes to the response groups or individuals. This may include changes to the names or contact information listed in the plan. Technology changes affecting the plan may include referenced information sources, communication systems, or ticketing systems.

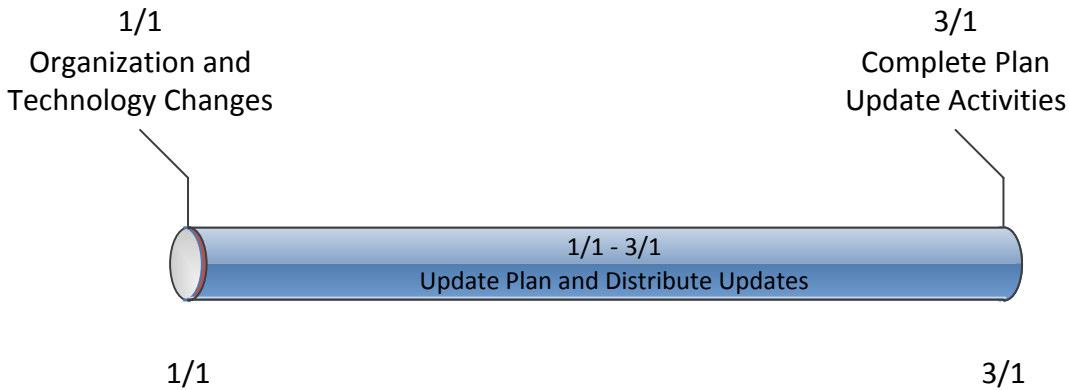


Figure 2: Timeline for Plan Changes in 3.2

When notifying individuals of response plan changes, entities should keep in mind that recovery plans may be considered BES Cyber System Information, and they should take the appropriate measures to prevent unauthorized disclosure of recovery plan information. For example, the recovery plan itself, or other sensitive information about the recovery plan, should be redacted from Email or other unencrypted transmission.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

Preventative activities can lower the number of incidents, but not all incidents can be prevented. A preplanned recovery capability is, therefore, necessary for rapidly recovering from incidents, minimizing loss and destruction, mitigating the weaknesses that were exploited, and restoring computing services so that planned and consistent recovery action to restore BES Cyber System functionality occurs.

Summary of Changes: Added provisions to protect data that would be useful in the investigation of an event that results in the need for a Cyber System recovery plan to be utilized.

Reference to prior version: (Part 1.1) CIP-009, R1.1

Change Description and Justification: (Part 1.1)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 1.2) CIP-009, R1.2

Change Description and Justification: (Part 1.2)

Minor wording changes; essentially unchanged.

Reference to prior version: (Part 1.3) CIP-009, R4

Change Description and Justification: (Part 1.3)

Addresses FERC Order Paragraph 739 and 748. The modified wording was abstracted from Paragraph 744.

Reference to prior version: (Part 1.4) New Requirement

Change Description and Justification: (Part 1.4)

Addresses FERC Order Section 739 and 748.

Reference to prior version: (Part 1.5) New Requirement

Change Description and Justification: (Part 1.5)

Added requirement to address FERC Order No. 706, Paragraph 706.

Rationale for R2:

The implementation of an effective recovery plan mitigates the risk to the reliable operation of the BES by reducing the time to recover from various hazards affecting BES Cyber Systems. This requirement ensures continued implementation of the response plans.

Requirement Part 2.2 provides further assurance in the information (e.g. backup tapes, mirrored hot-sites, etc.) necessary to recover BES Cyber Systems. A full test is not feasible in most instances due to the amount of recovery information, and the Responsible Entity must determine a sampling that provides assurance in the usability of the information.

Summary of Changes. Added operational testing for recovery of BES Cyber Systems.

Reference to prior version: (Part 2.1) CIP-009, R2

Change Description and Justification: (Part 2.1)

Minor wording change; essentially unchanged.

Reference to prior version: (Part 2.2) CIP-009, R5

Change Description and Justification: (Part 2.2)

Specifies what to test and makes clear the test can be a representative sampling. These changes, along with Requirement Part 1.4 address the FERC Order No. 706, Paragraphs 739 and 748 related to testing of backups by providing high confidence the information will actually recover the system as necessary.

Reference to prior version: (Part 2.3) CIP-009, R2

Change Description and Justification: (Part 2.3)

Addresses FERC Order No. 706, Paragraph 725 to add the requirement that the recovery plan test be a full operational test once every 3 years.

Rationale for R3:

To improve the effectiveness of BES Cyber System recovery plan(s) following a test, and to ensure the maintenance and distribution of the recovery plan(s). Responsible Entities achieve this by (i) performing a lessons learned review in 3.1 and (ii) revising the plan in 3.2 based on specific changes in the organization or technology that would impact plan execution. In both instances when the plan needs to change, the Responsible Entity updates and distributes the plan.

Summary of Changes: Makes clear when to perform lessons learned review of the plan and specifies the timeframe for updating the recovery plan.

Reference to prior version: (Part 3.1) CIP-009, R1 and R3

Change Description and Justification: (Part 3.1)

Added the timeframes for performing lessons learned and completing the plan updates. This requirement combines all three activities in one place. Where previous versions specified 30 calendar days for performing lessons learned, followed by additional time for updating recovery plans and notification, this requirement combines those activities into a single timeframe.

Reference to prior version: (Part 3.2) New Requirement

Change Description and Justification: (Part 3.2)

Specifies the activities required to maintain the plan. The previous version required entities to update the plan in response to any changes. The modifications make clear the specific changes that would require an update.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change “Control Center” to “control center”	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	

Guidelines and Technical Basis

3		Updated version number from -2 to -3 In Requirement 1.6, deleted the sentence pertaining to removing component or system from service in order to perform testing, in response to FERC order issued September 30, 2009.	
3	12/16/09	Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-009-5. (Order becomes effective on 2/3/14.)	
<u>5(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Cyber Security — Configuration Change Management and Vulnerability Assessments
2. **Number:** CIP-010-1(X)
3. **Purpose:** To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-010-1(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

- 24 Months Minimum** – CIP-010-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
- In those jurisdictions where no regulatory approval is required, CIP-010-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-010-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk

Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the applicability column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

B. Requirements and Measures

R1. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Develop a baseline configuration, individually or by group, which shall include the following items:</p> <ol style="list-style-type: none"> 1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists; 1.1.2. Any commercially available or open-source application software (including version) intentionally installed; 1.1.3. Any custom software installed; 1.1.4. Any logical network accessible ports; and 1.1.5. Any security patches applied. 	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • A spreadsheet identifying the required items of the baseline configuration for each Cyber Asset, individually or by group; or • A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Authorize and document changes that deviate from the existing baseline configuration.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • A change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or • Documentation that the change was performed in accordance with the requirement.

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.</p>	<p>An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.</p>
1.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For a change that deviates from the existing baseline configuration:</p> <ol style="list-style-type: none"> 1.4.1. Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change; 1.4.2. Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and 1.4.3. Document the results of the verification. 	<p>An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.</p>

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.5	High Impact BES Cyber Systems	<p>Where technically feasible, for each change that deviates from the existing baseline configuration:</p> <p>1.5.1. Prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and</p> <p>1.5.2. Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p>	<p>An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including of the date of the test.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-1(X) Table R2 – Configuration Monitoring			
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes.	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected.

- R3.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3– Vulnerability Assessments*. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning and Operations Planning]
- M3.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-1(X) Table R3 – Vulnerability Assessments			
Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>At least once every 15 calendar months, conduct a paper or active vulnerability assessment.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment;; or • A document listing the date of the assessment and the output of any tools used to perform the assessment.

CIP-010-1(X) Table R3 – Vulnerability Assessments			
Part	Applicable Systems	Requirements	Measures
3.2	High Impact BES Cyber Systems	<p>Where technically feasible, at least once every 36 calendar months:</p> <p>3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the BES Cyber System in a production environment; and</p> <p>3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p>	<p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.</p>

CIP-010-1(X) Table R3 – Vulnerability Assessments			
Part	Applicable Systems	Requirements	Measures
3.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PCA 	<p>Prior to adding a new applicable Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances and like replacements of the same type of Cyber Asset with a baseline configuration that models an existing baseline configuration of the previous or other existing Cyber Asset.</p>	<p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new Cyber Asset) and the output of any tools used to perform the assessment.</p>
3.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.</p>	<p>An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).</p>

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	<p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only four of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline</p>	<p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only three of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 and</p>	<p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only two of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 and identified</p>	<p>The Responsible Entity has not documented or implemented any configuration change management process(es). (R1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only one of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1) OR	identified deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1) OR The Responsible Entity has a process(es) to determine required	deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1) OR The Responsible Entity has a process(es) that requires authorization and documentation for	implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration and identified deficiencies in the verification documentation but did not assess or correct the deficiencies. (1.4.3)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration but did not identify,</p>	<p>security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration and identified deficiencies in the determination of affected security controls, but did not assess, or correct the deficiencies. (1.4.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline</p>	<p>changes that deviate from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) that requires authorization and documentation for changes that deviate from the existing baseline configuration but did not identify, assess, or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to update</p>	<p>assess, and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) that requires authorization and documentation of changes that deviate from the existing baseline configuration. (1.2)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration.(1.3)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			assess, or correct the deficiencies in the verification documentation. (1.4.3)	configuration but did not identify, assess, or correct the deficiencies in the determination of affected security controls. (1.4.1)	baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.3) OR The Responsible Entity has a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration but did not identify, assess,	OR The Responsible Entity does not have a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration. (1.4.1) OR The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					or correct the deficiencies. (1.3) OR The Responsible Entity has a process(es) to verify that required security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration and identified deficiencies in required controls, but did not assess, or correct the deficiencies. (1.4.2) OR The Responsible Entity has a process(es) to verify that required	not verify and document that the required controls were not adversely affected following the change. (1.4.2 & 1.4.3) OR The Responsible Entity does not have a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration. (1.5.1) OR The Responsible Entity does not have a process to document the test results and, if using a test environment,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration but did not identify, assess, or correct the deficiencies in the required controls. (1.4.2) OR The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration, and identified deficiencies but did not assess or correct	document the differences between the test and production environments. (1.5.2)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					the deficiencies. (1.5.1) OR The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration but did not identify, assess, or correct the deficiencies. (1.5.1) OR The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					environments and identified deficiencies but did not assess or correct the deficiencies. (1.5.2) OR The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production environments, but did not identify, assess, or correct the deficiencies. (1.5.2)	
R2	Operations Planning	Medium	N/A	N/A	N/A	The Responsible Entity has not documented or implemented a process(es) to monitor for,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days. (2.1) OR The Responsible Entity has documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days and identified deficiencies but did not assess or correct the deficiencies. (2.1) OR The Responsible Entity has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days but did not identify, assess, or correct the deficiencies. (2.1)
R3	Long-term Planning and Operations Planning	Medium	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 15 months,	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 18 months, but less than 21, months	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 21 months, but less than 24 months,	The Responsible Entity has not implemented any vulnerability assessment processes for one of its applicable BES Cyber Systems. (R3) OR The Responsible Entity has implemented one or more documented

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>but less than 18 months, since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 36 months, but less than 39 months, since the last active assessment on one of its applicable BES</p>	<p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 39 months, but less than 42 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p>	<p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 42 months, but less than 45 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p>	<p>vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 24 months since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 45 months since the last active</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Cyber Systems. (3.2)			assessment on one of its applicable BES Cyber Systems.(3.2) OR The Responsible Entity has implemented and documented one or more vulnerability assessment processes for each of its applicable BES Cyber Systems, but did not perform the active vulnerability assessment in a manner that models an existing baseline configuration of its applicable BES Cyber Systems. (3.3) OR The Responsible Entity has implemented one or more documented

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						vulnerability assessment processes for each of its applicable BES Cyber Systems, but has not documented the results of the vulnerability assessments, the action plans to remediate or mitigate vulnerabilities identified in the assessments, the planned date of completion of the action plan, and the execution status of the mitigation plans. (3.4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Baseline Configuration

The concept of establishing a Cyber Asset’s baseline configuration is meant to provide clarity on requirement language found in previous CIP standard versions. Modification of any item within an applicable Cyber Asset’s baseline configuration provides the triggering mechanism for when entities must apply change management processes.

Baseline configurations in CIP-010 consist of five different items: Operating system/firmware, commercially available software or open-source application software, custom software, logical network accessible port identification, and security patches. Operating system information identifies the software and version that is in use on the Cyber Asset. In cases where an independent operating system does not exist (such as for a protective relay), then firmware information should be identified. Commercially available or open-source application software identifies applications that were intentionally installed on the cyber asset. The use of the term “intentional” was meant to ensure that only software applications that were determined to be necessary for Cyber Asset use should be included in the baseline configuration. The SDT does not intend for notepad, calculator, DLL, device drivers, or other applications included in an operating system package as commercially available or open-source application software to be

included. Custom software installed may include scripts developed for local entity functions or other custom software developed for a specific task or function for the entity's use. If additional software was intentionally installed and is not commercially available or open-source, then this software could be considered custom software. If a specific device needs to communicate with another device outside the network, communications need to be limited to only the devices that need to communicate per the requirement in CIP-007-5(X). Those ports which are accessible need to be included in the baseline. Security patches applied would include all historical and current patches that have been applied on the cyber asset. While CIP-007-5(X) R2.1 requires entities to track, evaluate, and install security patches, CIP-010 R1.1.5 requires entities to list all applied historical and current patches.

Further guidance can be understood with the following example that details the baseline configuration for a serial-only microprocessor relay:

Asset #051028 at Substation Alpha

- R1.1.1 – Firmware: [MANUFACTURER]-[MODEL]-XYZ-1234567890-ABC
- R1.1.2 – Not Applicable
- R1.1.3 – Not Applicable
- R1.1.4 – Not Applicable
- R1.1.5 – Patch 12345, Patch 67890, Patch 34567, Patch 437823

Also, for a typical IT system, the baseline configuration could reference an IT standard that includes configuration details. An entity would be expected to provide that IT standard as part of their compliance evidence.

Cyber Security Controls

The use of cyber security controls refers specifically to controls referenced and applied according to CIP-005 and CIP-007. The concept presented in the relevant requirement sub-parts in CIP-010 R1 is that an entity is to identify/verify controls from CIP-005 and CIP-007 that could be impacted for a change that deviates from the existing baseline configuration. The SDT does not intend for Responsible Entities to identify/verify all controls located within CIP-005 and CIP-007 for each change. The Responsible Entity is only to identify/verify those control(s) that could be affected by the baseline configuration change. For example, changes that affect logical network ports would only involve CIP-007 R1 (Ports and Services), while changes that affect security patches would only involve CIP-007 R2 (Security Patch Management). The SDT chose not to identify the specific requirements from CIP-005 and CIP-007 in CIP-010 language as the intent of the related requirements is to be able to identify/verify any of the controls in those standards that are affected as a result of a change to the baseline configuration. The SDT believes it possible that all requirements from CIP-005 and CIP-007 may be identified for a

major change to the baseline configuration, and therefore, CIP-005 and CIP-007 was cited at the standard-level versus the requirement-level.

Test Environment

The Control Center test environment (or production environment where the test is performed in a manner that minimizes adverse effects) should model the baseline configuration, but may have a different set of components. For instance, an entity may have a BES Cyber System that runs a database on one component and a web server on another component. The test environment may have the same operating system, security patches, network accessible ports, and software, but have both the database and web server running on a single component instead of multiple components.

Additionally, the Responsible Entity should note that wherever a test environment (or production environment where the test is performed in a manner that minimizes adverse effects) is mentioned, the requirement is to “model” the baseline configuration and not duplicate it exactly. This language was chosen deliberately in order to allow for individual elements of a BES Cyber System at a Control Center to be modeled that may not otherwise be able to be replicated or duplicated exactly; such as, but not limited to, a legacy map-board controller or the numerous data communication links from the field or to other Control Centers (such as by ICCP).

Requirement R2:

The SDT’s intent of R2 is to require automated monitoring of the BES Cyber System. However, the SDT understands that there may be some Cyber Assets where automated monitoring may not be possible (such as a GPS time clock). For that reason, automated technical monitoring was not explicitly required, and a Responsible Entity may choose to accomplish this requirement through manual procedural controls.

Requirement R3:

The Responsible Entity should note that the requirement provides a distinction between paper and active vulnerability assessments. The justification for this distinction is well-documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking. In developing their vulnerability assessment processes, Responsible Entities are strongly encouraged to include at least the following elements, several of which are referenced in CIP-005 and CIP-007:

Paper Vulnerability Assessment:

1. Network Discovery - A review of network connectivity to identify all Electronic Access Points to the Electronic Security Perimeter.
2. Network Port and Service Identification - A review to verify that all enabled ports and services have an appropriate business justification.

3. Vulnerability Review - A review of security rule-sets and configurations including controls for default accounts, passwords, and network management community strings.
4. Wireless Review - Identification of common types of wireless networks (such as 802.11a/b/g/n) and a review of their controls if they are in any way used for BES Cyber System communications.

Active Vulnerability Assessment:

1. Network Discovery - Use of active discovery tools to discover active devices and identify communication paths in order to verify that the discovered network architecture matches the documented architecture.
2. Network Port and Service Identification – Use of active discovery tools (such as Nmap) to discover open ports and services.
3. Vulnerability Scanning – Use of a vulnerability scanning tool to identify network accessible ports and services along with the identification of known vulnerabilities associated with services running on those ports.
4. Wireless Scanning – Use of a wireless scanning tool to discover wireless signals and networks in the physical perimeter of a BES Cyber System. Serves to identify unauthorized wireless devices within the range of the wireless scanning tool.

In addition, Responsible Entities are strongly encouraged to review NIST SP800-115 for additional guidance on how to conduct a vulnerability assessment.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The configuration change management processes are intended to prevent unauthorized modifications to BES Cyber Systems.

Reference to prior version: (Part 1.1) New Requirement

Change Rationale: (Part 1.1)

The baseline configuration requirement was incorporated from the DHS Catalog for Control Systems Security. The baseline requirement is also intended to clarify precisely when a change management process must be invoked and which elements of the configuration must be examined.

Reference to prior version: (Part 1.2) CIP-007-3, R9; CIP-003-3, R6

Change Rationale: (Part 1.2)

The SDT added requirement to explicitly authorize changes. This requirement was previously implied by CIP-003-3, Requirement R6.

Reference to prior version: (Part 1.3) CIP-007-3, R9; CIP-005-3, R5

Change Rationale: (Part 1.3)

Document maintenance requirement due to a BES Cyber System change is equivalent to the requirements in the previous versions of the standard.

Reference to prior version: (Part 1.4) CIP-007-3, R1

Change Rationale: (Part 1.4)

The SDT attempted to provide clarity on when testing must occur and removed requirement for specific test procedures because it is implicit in the performance of the requirement.

Reference to prior version: (Part 1.5) CIP-007-3, R1

Change Rationale: (Part 1.5)

This requirement provides clarity on when testing must occur and requires additional testing to ensure that accidental consequences of planned changes are appropriately managed.

This change addresses FERC Order No. 706, Paragraphs 397, 609, 610, and 611.

Rationale for R2:

The configuration monitoring processes are intended to detect unauthorized modifications to BES Cyber Systems.

Reference to prior version: (Part 2.1) New Requirement

Change Rationale: (Part 2.1)

The monitoring of the configuration of the BES Cyber System provides an express acknowledgement of the need to consider malicious actions along with intentional changes.

This requirement was added after review of the DHS Catalog of Control System Security and to address FERC Order No. 706, Paragraph 397.

Thirty-five Calendar days allows for a “once-a-month” frequency with slight flexibility to account for months with 31 days or for beginning or endings of months on weekends.

Rationale for R3:

The vulnerability assessment processes are intended to act as a component in an overall program to periodically ensure the proper implementation of cyber security controls as well as to continually improve the security posture of BES Cyber Systems.

The vulnerability assessment performed for this requirement may be a component of deficiency identification, assessment, and correction.

Reference to prior version: (Part 3.1) CIP-005-4, R4; CIP-007-4, R8

Change Rationale: (Part 3.1)

As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.

Reference to prior version: (Part 3.2) New Requirement

Change Rationale: (Part 3.2)

FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.

As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.

Reference to prior version: (Part 3.3) New Requirement

Change Rationale: (Part 3.3)

FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.

Reference to prior version: (Part 3.4) CIP-005-3, R4.5; CIP-007-3, R8.4

Change Rationale: (Part 3.4)

Added a requirement for an entity planned date of completion as per the directive in FERC Order No. 706, Paragraph 643.

Version History

Version	Date	Action	Change Tracking
1	11/26/12	Adopted by the NERC Board of Trustees.	Developed to define the configuration change management and vulnerability assessment requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706.
1	11/22/13	FERC Order issued approving CIP-010-1. (Order becomes effective on 2/3/14.)	

Guidelines and Technical Basis

1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
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A. Introduction

1. **Title:** Cyber Security — Configuration Change Management and Vulnerability Assessments
2. **Number:** CIP-010-1(X)
3. **Purpose:** To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-010-1(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

- 24 Months Minimum** – CIP-010-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
- In those jurisdictions where no regulatory approval is required, CIP-010-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees’ approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-010-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, “*Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].*” The referenced table requires the applicable items in the procedures for the requirement’s common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented

processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology (“NIST”) Risk

Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the applicability column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

B. Requirements and Measures

R1. Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R1 – Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Develop a baseline configuration, individually or by group, which shall include the following items:</p> <ol style="list-style-type: none"> 1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists; 1.1.2. Any commercially available or open-source application software (including version) intentionally installed; 1.1.3. Any custom software installed; 1.1.4. Any logical network accessible ports; and 1.1.5. Any security patches applied. 	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • A spreadsheet identifying the required items of the baseline configuration for each Cyber Asset, individually or by group; or • A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Authorize and document changes that deviate from the existing baseline configuration.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • A change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or • Documentation that the change was performed in accordance with the requirement.

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.</p>	<p>An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.</p>
1.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>For a change that deviates from the existing baseline configuration:</p> <ol style="list-style-type: none"> 1.4.1. Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change; 1.4.2. Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and 1.4.3. Document the results of the verification. 	<p>An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.</p>

CIP-010-1(X) Table R1 – Configuration Change Management			
Part	Applicable Systems	Requirements	Measures
1.5	High Impact BES Cyber Systems	<p>Where technically feasible, for each change that deviates from the existing baseline configuration:</p> <p>1.5.1. Prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and</p> <p>1.5.2. Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p>	<p>An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including of the date of the test.</p>

- R2.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring*. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R2 – Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-1(X) Table R2 – Configuration Monitoring			
Part	Applicable Systems	Requirements	Measures
2.1	High Impact BES Cyber Systems and their associated: <ol style="list-style-type: none"> 1. EACMS; and 2. PCA 	Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes.	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected.

- R3.** Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3– Vulnerability Assessments*. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning and Operations Planning]
- M3.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-010-1(X) Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-010-1(X) Table R3 – Vulnerability Assessments

Part	Applicable Systems	Requirements	Measures
3.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>At least once every 15 calendar months, conduct a paper or active vulnerability assessment.</p>	<p>Examples of evidence may include, but are not limited to:</p> <ul style="list-style-type: none"> • A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment;; or • A document listing the date of the assessment and the output of any tools used to perform the assessment.

CIP-010-1(X) Table R3 – Vulnerability Assessments			
Part	Applicable Systems	Requirements	Measures
3.2	High Impact BES Cyber Systems	<p>Where technically feasible, at least once every 36 calendar months:</p> <p>3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the BES Cyber System in a production environment; and</p> <p>3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.</p>	<p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.</p>

CIP-010-1(X) Table R3 – Vulnerability Assessments			
Part	Applicable Systems	Requirements	Measures
3.3	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PCA 	<p>Prior to adding a new applicable Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances and like replacements of the same type of Cyber Asset with a baseline configuration that models an existing baseline configuration of the previous or other existing Cyber Asset.</p>	<p>An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new Cyber Asset) and the output of any tools used to perform the assessment.</p>
3.4	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.</p>	<p>An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).</p>

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	<p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only four of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline</p>	<p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only three of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 and</p>	<p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only two of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 and identified</p>	<p>The Responsible Entity has not documented or implemented any configuration change management process(es). (R1)</p> <p>OR</p> <p>The Responsible Entity has documented and implemented a configuration change management process(es) that includes only one of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)</p> <p>OR</p> <p>The Responsible Entity has documented and</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes all of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1) OR	identified deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes four of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1) OR The Responsible Entity has a process(es) to determine required	deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes three of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify, assess, and correct the deficiencies. (1.1) OR The Responsible Entity has a process(es) that requires authorization and documentation for	implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 and identified deficiencies but did not assess and correct the deficiencies. (1.1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes two or fewer of the required baseline items listed in 1.1.1 through 1.1.5 but did not identify,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration and identified deficiencies in the verification documentation but did not assess or correct the deficiencies. (1.4.3)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to perform steps in 1.4.1 and 1.4.2 for a change(s) that deviates from the existing baseline configuration but did not identify,</p>	<p>security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration and identified deficiencies in the determination of affected security controls, but did not assess, or correct the deficiencies. (1.4.1)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline</p>	<p>changes that deviate from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) that requires authorization and documentation for changes that deviate from the existing baseline configuration but did not identify, assess, or correct the deficiencies. (1.2)</p> <p>OR</p> <p>The Responsible Entity has a process(es) to update</p>	<p>assess, and correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) that requires authorization and documentation of changes that deviate from the existing baseline configuration. (1.2)</p> <p>OR</p> <p>The Responsible Entity does not have a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration.(1.3)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			assess, or correct the deficiencies in the verification documentation. (1.4.3)	configuration but did not identify, assess, or correct the deficiencies in the determination of affected security controls. (1.4.1)	baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration and identified deficiencies but did not assess or correct the deficiencies. (1.3) OR The Responsible Entity has a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration but did not identify, assess,	OR The Responsible Entity does not have a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration. (1.4.1) OR The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration but did

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					or correct the deficiencies. (1.3) OR The Responsible Entity has a process(es) to verify that required security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration and identified deficiencies in required controls, but did not assess, or correct the deficiencies. (1.4.2) OR The Responsible Entity has a process(es) to verify that required	not verify and document that the required controls were not adversely affected following the change. (1.4.2 & 1.4.3) OR The Responsible Entity does not have a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration. (1.5.1) OR The Responsible Entity does not have a process to document the test results and, if using a test environment,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>security controls in CIP-005 and CIP-007 are not adversely affected by a change(s) that deviates from the existing baseline configuration but did not identify, assess, or correct the deficiencies in the required controls. (1.4.2)</p> <p>OR</p> <p>The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration, and identified deficiencies but did not assess or correct</p>	<p>document the differences between the test and production environments. (1.5.2)</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					the deficiencies. (1.5.1) OR The Responsible Entity has a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration but did not identify, assess, or correct the deficiencies. (1.5.1) OR The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					<p>environments and identified deficiencies but did not assess or correct the deficiencies. (1.5.2)</p> <p>OR</p> <p>The Responsible Entity has a process to document the test results and, if using a test environment, document the differences between the test and production environments, but did not identify, assess, or correct the deficiencies. (1.5.2)</p>	
R2	Operations Planning	Medium	N/A	N/A	N/A	The Responsible Entity has not documented or implemented a process(es) to monitor for,

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days. (2.1) OR The Responsible Entity has documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days and identified deficiencies but did not assess or correct the deficiencies. (2.1) OR The Responsible Entity has

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						documented and implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days but did not identify, assess, or correct the deficiencies. (2.1)
R3	Long-term Planning and Operations Planning	Medium	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 15 months,	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 18 months, but less than 21, months	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 21 months, but less than 24 months,	The Responsible Entity has not implemented any vulnerability assessment processes for one of its applicable BES Cyber Systems. (R3) OR The Responsible Entity has implemented one or more documented

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>but less than 18 months, since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 36 months, but less than 39 months, since the last active assessment on one of its applicable BES</p>	<p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 39 months, but less than 42 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p>	<p>since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 42 months, but less than 45 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)</p>	<p>vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 24 months since the last assessment on one of its applicable BES Cyber Systems. (3.1)</p> <p>OR</p> <p>The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 45 months since the last active</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Cyber Systems. (3.2)			assessment on one of its applicable BES Cyber Systems.(3.2) OR The Responsible Entity has implemented and documented one or more vulnerability assessment processes for each of its applicable BES Cyber Systems, but did not perform the active vulnerability assessment in a manner that models an existing baseline configuration of its applicable BES Cyber Systems. (3.3) OR The Responsible Entity has implemented one or more documented

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						vulnerability assessment processes for each of its applicable BES Cyber Systems, but has not documented the results of the vulnerability assessments, the action plans to remediate or mitigate vulnerabilities identified in the assessments, the planned date of completion of the action plan, and the execution status of the mitigation plans. (3.4)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)’s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Baseline Configuration

The concept of establishing a Cyber Asset’s baseline configuration is meant to provide clarity on requirement language found in previous CIP standard versions. Modification of any item within an applicable Cyber Asset’s baseline configuration provides the triggering mechanism for when entities must apply change management processes.

Baseline configurations in CIP-010 consist of five different items: Operating system/firmware, commercially available software or open-source application software, custom software, logical network accessible port identification, and security patches. Operating system information identifies the software and version that is in use on the Cyber Asset. In cases where an independent operating system does not exist (such as for a protective relay), then firmware information should be identified. Commercially available or open-source application software identifies applications that were intentionally installed on the cyber asset. The use of the term “intentional” was meant to ensure that only software applications that were determined to be necessary for Cyber Asset use should be included in the baseline configuration. The SDT does not intend for notepad, calculator, DLL, device drivers, or other applications included in an operating system package as commercially available or open-source application software to be

included. Custom software installed may include scripts developed for local entity functions or other custom software developed for a specific task or function for the entity's use. If additional software was intentionally installed and is not commercially available or open-source, then this software could be considered custom software. If a specific device needs to communicate with another device outside the network, communications need to be limited to only the devices that need to communicate per the requirement in CIP-007-5(X). Those ports which are accessible need to be included in the baseline. Security patches applied would include all historical and current patches that have been applied on the cyber asset. While CIP-007-5(X) R2.1 requires entities to track, evaluate, and install security patches, CIP-010 R1.1.5 requires entities to list all applied historical and current patches.

Further guidance can be understood with the following example that details the baseline configuration for a serial-only microprocessor relay:

Asset #051028 at Substation Alpha

- R1.1.1 – Firmware: [MANUFACTURER]-[MODEL]-XYZ-1234567890-ABC
- R1.1.2 – Not Applicable
- R1.1.3 – Not Applicable
- R1.1.4 – Not Applicable
- R1.1.5 – Patch 12345, Patch 67890, Patch 34567, Patch 437823

Also, for a typical IT system, the baseline configuration could reference an IT standard that includes configuration details. An entity would be expected to provide that IT standard as part of their compliance evidence.

Cyber Security Controls

The use of cyber security controls refers specifically to controls referenced and applied according to CIP-005 and CIP-007. The concept presented in the relevant requirement sub-parts in CIP-010 R1 is that an entity is to identify/verify controls from CIP-005 and CIP-007 that could be impacted for a change that deviates from the existing baseline configuration. The SDT does not intend for Responsible Entities to identify/verify all controls located within CIP-005 and CIP-007 for each change. The Responsible Entity is only to identify/verify those control(s) that could be affected by the baseline configuration change. For example, changes that affect logical network ports would only involve CIP-007 R1 (Ports and Services), while changes that affect security patches would only involve CIP-007 R2 (Security Patch Management). The SDT chose not to identify the specific requirements from CIP-005 and CIP-007 in CIP-010 language as the intent of the related requirements is to be able to identify/verify any of the controls in those standards that are affected as a result of a change to the baseline configuration. The SDT believes it possible that all requirements from CIP-005 and CIP-007 may be identified for a

major change to the baseline configuration, and therefore, CIP-005 and CIP-007 was cited at the standard-level versus the requirement-level.

Test Environment

The Control Center test environment (or production environment where the test is performed in a manner that minimizes adverse effects) should model the baseline configuration, but may have a different set of components. For instance, an entity may have a BES Cyber System that runs a database on one component and a web server on another component. The test environment may have the same operating system, security patches, network accessible ports, and software, but have both the database and web server running on a single component instead of multiple components.

Additionally, the Responsible Entity should note that wherever a test environment (or production environment where the test is performed in a manner that minimizes adverse effects) is mentioned, the requirement is to “model” the baseline configuration and not duplicate it exactly. This language was chosen deliberately in order to allow for individual elements of a BES Cyber System at a Control Center to be modeled that may not otherwise be able to be replicated or duplicated exactly; such as, but not limited to, a legacy map-board controller or the numerous data communication links from the field or to other Control Centers (such as by ICCP).

Requirement R2:

The SDT’s intent of R2 is to require automated monitoring of the BES Cyber System. However, the SDT understands that there may be some Cyber Assets where automated monitoring may not be possible (such as a GPS time clock). For that reason, automated technical monitoring was not explicitly required, and a Responsible Entity may choose to accomplish this requirement through manual procedural controls.

Requirement R3:

The Responsible Entity should note that the requirement provides a distinction between paper and active vulnerability assessments. The justification for this distinction is well-documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking. In developing their vulnerability assessment processes, Responsible Entities are strongly encouraged to include at least the following elements, several of which are referenced in CIP-005 and CIP-007:

Paper Vulnerability Assessment:

1. Network Discovery - A review of network connectivity to identify all Electronic Access Points to the Electronic Security Perimeter.
2. Network Port and Service Identification - A review to verify that all enabled ports and services have an appropriate business justification.

3. Vulnerability Review - A review of security rule-sets and configurations including controls for default accounts, passwords, and network management community strings.
4. Wireless Review - Identification of common types of wireless networks (such as 802.11a/b/g/n) and a review of their controls if they are in any way used for BES Cyber System communications.

Active Vulnerability Assessment:

1. Network Discovery - Use of active discovery tools to discover active devices and identify communication paths in order to verify that the discovered network architecture matches the documented architecture.
2. Network Port and Service Identification – Use of active discovery tools (such as Nmap) to discover open ports and services.
3. Vulnerability Scanning – Use of a vulnerability scanning tool to identify network accessible ports and services along with the identification of known vulnerabilities associated with services running on those ports.
4. Wireless Scanning – Use of a wireless scanning tool to discover wireless signals and networks in the physical perimeter of a BES Cyber System. Serves to identify unauthorized wireless devices within the range of the wireless scanning tool.

In addition, Responsible Entities are strongly encouraged to review NIST SP800-115 for additional guidance on how to conduct a vulnerability assessment.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The configuration change management processes are intended to prevent unauthorized modifications to BES Cyber Systems.

Reference to prior version: (Part 1.1) New Requirement

Change Rationale: (Part 1.1)

The baseline configuration requirement was incorporated from the DHS Catalog for Control Systems Security. The baseline requirement is also intended to clarify precisely when a change management process must be invoked and which elements of the configuration must be examined.

Reference to prior version: (Part 1.2) CIP-007-3, R9; CIP-003-3, R6

Change Rationale: (Part 1.2)

The SDT added requirement to explicitly authorize changes. This requirement was previously implied by CIP-003-3, Requirement R6.

Reference to prior version: (Part 1.3) CIP-007-3, R9; CIP-005-3, R5

Change Rationale: (Part 1.3)

Document maintenance requirement due to a BES Cyber System change is equivalent to the requirements in the previous versions of the standard.

Reference to prior version: (Part 1.4) CIP-007-3, R1

Change Rationale: (Part 1.4)

The SDT attempted to provide clarity on when testing must occur and removed requirement for specific test procedures because it is implicit in the performance of the requirement.

Reference to prior version: (Part 1.5) CIP-007-3, R1

Change Rationale: (Part 1.5)

This requirement provides clarity on when testing must occur and requires additional testing to ensure that accidental consequences of planned changes are appropriately managed.

This change addresses FERC Order No. 706, Paragraphs 397, 609, 610, and 611.

Rationale for R2:

The configuration monitoring processes are intended to detect unauthorized modifications to BES Cyber Systems.

Reference to prior version: (Part 2.1) New Requirement

Change Rationale: (Part 2.1)

The monitoring of the configuration of the BES Cyber System provides an express acknowledgement of the need to consider malicious actions along with intentional changes.

This requirement was added after review of the DHS Catalog of Control System Security and to address FERC Order No. 706, Paragraph 397.

Thirty-five Calendar days allows for a “once-a-month” frequency with slight flexibility to account for months with 31 days or for beginning or endings of months on weekends.

Rationale for R3:

The vulnerability assessment processes are intended to act as a component in an overall program to periodically ensure the proper implementation of cyber security controls as well as to continually improve the security posture of BES Cyber Systems.

The vulnerability assessment performed for this requirement may be a component of deficiency identification, assessment, and correction.

Reference to prior version: (Part 3.1) CIP-005-4, R4; CIP-007-4, R8

Change Rationale: (Part 3.1)

As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.

Reference to prior version: (Part 3.2) New Requirement

Change Rationale: (Part 3.2)

FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.

As suggested in FERC Order No. 706, Paragraph 644, the details for what should be included in the assessment are left to guidance.

Reference to prior version: (Part 3.3) New Requirement

Change Rationale: (Part 3.3)

FERC Order No. 706, Paragraphs 541, 542, 543, 544, 545, and 547.

Reference to prior version: (Part 3.4) CIP-005-3, R4.5; CIP-007-3, R8.4

Change Rationale: (Part 3.4)

Added a requirement for an entity planned date of completion as per the directive in FERC Order No. 706, Paragraph 643.

Version History

Version	Date	Action	Change Tracking
1	11/26/12	Adopted by the NERC Board of Trustees.	Developed to define the configuration change management and vulnerability assessment requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706.
1	11/22/13	FERC Order issued approving CIP-010-1. (Order becomes effective on 2/3/14.)	

Guidelines and Technical Basis

<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>
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A. Introduction

1. **Title:** Cyber Security — Information Protection
2. **Number:** CIP-011-1(X)
3. **Purpose:** To prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-011-1(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-011-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.
2. In those jurisdictions where no regulatory approval is required, CIP-011-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-011-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies**, . . .

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies,

assesses, and corrects deficiencies, . . ." elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

"Applicable Systems" Columns in Tables:

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact

and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)**– Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M1.** Evidence for the information protection program must include the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-1(X) Table R1 – Information Protection			
Part	Applicable Systems	Requirements	Measures
1.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Method(s) to identify information that meets the definition of BES Cyber System Information.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Documented method to identify BES Cyber System Information from entity’s information protection program; or • Indications on information (e.g., labels or classification) that identify BES Cyber System Information as designated in the entity’s information protection program; or • Training materials that provide personnel with sufficient knowledge to recognize BES Cyber System Information; or • Repository or electronic and physical location designated for housing BES Cyber System Information in the entity’s information protection program.

CIP-011-1(X) Table R1 – Information Protection			
Part	Applicable Systems	Requirement	Measure
1.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Procedure(s) for protecting and securely handling BES Cyber System Information, including storage, transit, and use.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Procedures for protecting and securely handling, which include topics such as storage, security during transit, and use of BES Cyber System Information; or • Records indicating that BES Cyber System Information is handled in a manner consistent with the entity’s documented procedure(s).

- R2.** Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Prior to the release for reuse of applicable Cyber Assets that contain BES Cyber System Information (except for reuse within other systems identified in the “Applicable Systems” column), the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Records tracking sanitization actions taken to prevent unauthorized retrieval of BES Cyber System Information such as clearing, purging, or destroying; or • Records tracking actions such as encrypting, retaining in the Physical Security Perimeter or other methods used to prevent unauthorized retrieval of BES Cyber System Information.

CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Prior to the disposal of applicable Cyber Assets that contain BES Cyber System Information, the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset or destroy the data storage media.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Records that indicate that data storage media was destroyed prior to the disposal of an applicable Cyber Asset; or • Records of actions taken to prevent unauthorized retrieval of BES Cyber System Information prior to the disposal of an applicable Cyber Asset.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-011-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A		<p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information but did not identify,</p>	<p>The Responsible Entity has not documented or implemented a BES Cyber System Information protection program (R1).</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-011-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					assess, or correct the deficiencies. (1.1) OR The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.2) OR The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-011-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but did not identify, assess, or correct the deficiencies. (1.2)	
R2	Operations Planning	Lower	N/A	The Responsible Entity implemented one or more documented processes but did not include processes for reuse as to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.1)	The Responsible Entity implemented one or more documented processes but did not include disposal or media destruction processes to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.2)	The Responsible Entity has not documented or implemented any processes for applicable requirement parts in CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal. (R2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)'s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Responsible Entities are free to utilize existing change management and asset management systems. However, the information contained within those systems must be evaluated, as the information protection requirements still apply.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

This requirement mandates that BES Cyber System Information be identified. The Responsible Entity has flexibility in determining how to implement the requirement. The Responsible Entity should explain the method for identifying the BES Cyber System Information in their information protection program. For example, the Responsible Entity may decide to mark or label the documents. Identifying separate classifications of BES Cyber System Information is not specifically required. However, a Responsible Entity maintains the flexibility to do so if they desire. As long as the Responsible Entity's information protection program includes all applicable items, additional classification levels (e.g., confidential, public, internal use only, etc.) can be created that go above and beyond the requirements. If the entity chooses to use classifications, then the types of classifications used by the entity and any associated labeling should be documented in the entity's BES Cyber System Information Program.

The Responsible Entity may store all of the information about BES Cyber Systems in a separate repository or location (physical and/or electronic) with access control implemented. For example, the Responsible Entity's program could document that all information stored in an identified repository is considered BES Cyber System Information, the program may state that all information contained in an identified section of a specific repository is considered BES Cyber System Information, or the program may document that all hard copies of information are stored in a secured area of the building. Additional methods for implementing the requirement are suggested in the measures section. However, the methods listed in measures are not meant to be an exhaustive list of methods that the entity may choose to utilize for the identification of BES Cyber System Information.

The SDT does not intend that this requirement cover publicly available information, such as vendor manuals that are available via public websites or information that is deemed to be publicly releasable.

Information protection pertains to both digital and hardcopy information. R1.2 requires one or more procedures for the protection and secure handling BES Cyber System Information, including storage, transit, and use.

The entity's written Information Protection Program should explain how the entity handles aspects of information protection including specifying how BES Cyber System Information is to be securely handled during transit in order to protect against unauthorized access, misuse, or corruption and to protect confidentiality of the communicated BES Cyber System Information. For example, the use of a third-party communication service provider instead of organization-owned infrastructure may warrant the use of encryption to prevent unauthorized disclosure of information during transmission. The entity may choose to establish a trusted communications path for transit of BES Cyber System Information. The trusted communications path would utilize a logon or other security measures to provide secure handling during transit. The entity may employ alternative physical protective measures, such as the use of a courier or locked container for transmission of information. It is not the intent of this standard to mandate the use of one particular format for secure handling during transit.

A good Information Protection Program will document the circumstances under which BES Cyber System Information can be shared with or used by third parties. The organization should distribute or share information on a need-to-know basis. For example, the entity may specify that a confidentiality agreement, non-disclosure arrangement, contract, or written agreement of some kind concerning the handling of information must be in place between the entity and the third party. The entity's Information Protection Program should specify circumstances for sharing of BES Cyber System Information with and use by third parties, for example, use of a non-disclosure agreement. The entity should then follow their documented program. These requirements do not mandate one specific type of arrangement.

Requirement R2:

This requirement allows for BES Cyber Systems to be removed from service and analyzed with their media intact, as that should not constitute a release for reuse. However, following the

analysis, if the media is to be reused outside of a BES Cyber System or disposed of, the entity must take action to prevent the unauthorized retrieval of BES Cyber System Information from the media.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

If an applicable Cyber Asset is removed from the Physical Security Perimeter prior to action taken to prevent the unauthorized retrieval of BES Cyber System Information or destroying the data storage media, the responsible entity should maintain documentation that identifies the custodian for the data storage media while the data storage media is outside of the Physical Security Perimeter prior to actions taken by the entity as required in R2.

Media sanitization is the process used to remove information from system media such that reasonable assurance exists that the information cannot be retrieved or reconstructed. Media sanitization is generally classified into four categories: Disposal, clearing, purging, and destroying. For the purposes of this requirement, disposal by itself, with the exception of certain special circumstances, such as the use of strong encryption on a drive used in a SAN or other media, should never be considered acceptable. The use of clearing techniques may provide a suitable method of sanitization for media that is to be reused, whereas purging techniques may be more appropriate for media that is ready for disposal.

The following information from NIST SP800-88 provides additional guidance concerning the types of actions that an entity might take to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media:

Clear: One method to sanitize media is to use software or hardware products to overwrite storage space on the media with non-sensitive data. This process may include overwriting not only the logical storage location of a file(s) (e.g., file allocation table) but also may include all addressable locations. The security goal of the overwriting process is to replace written data with random data. Overwriting cannot be used for media that are damaged or not rewriteable. The media type and size may also influence whether overwriting is a suitable sanitization method [SP 800-36].

Purge: Degaussing and executing the firmware Secure Erase command (for ATA drives only) are acceptable methods for purging. Degaussing is exposing the magnetic media to a strong magnetic field in order to disrupt the recorded magnetic domains. A degausser is a device that generates a magnetic field used to sanitize magnetic media. Degaussers are rated based on the type (i.e., low energy or high energy) of magnetic media they can purge. Degaussers operate using either a strong permanent magnet or an electromagnetic coil. Degaussing can be an effective method for purging damaged or inoperative media, for purging media with exceptionally large storage capacities, or for quickly purging diskettes. [SP 800-36] Executing the firmware Secure Erase command (for ATA drives only) and degaussing are examples of acceptable methods for purging.

Degaussing of any hard drive assembly usually destroys the drive as the firmware that manages the device is also destroyed.

Destroy: There are many different types, techniques, and procedures for media destruction. Disintegration, Pulverization, Melting, and Incineration are sanitization methods designed to completely destroy the media. They are typically carried out at an outsourced metal destruction or licensed incineration facility with the specific capabilities to perform these activities effectively, securely, and safely. Optical mass storage media, including compact disks (CD, CD-RW, CD-R, CD-ROM), optical disks (DVD), and MO disks, must be destroyed by pulverizing, crosscut shredding or burning. In some cases such as networking equipment, it may be necessary to contact the manufacturer for proper sanitization procedure.

It is critical that an organization maintain a record of its sanitization actions to prevent unauthorized retrieval of BES Cyber System Information. Entities are strongly encouraged to review NIST SP800-88 for guidance on how to develop acceptable media sanitization processes.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The SDT's intent of the information protection program is to prevent unauthorized access to BES Cyber System Information.

Summary of Changes: CIP 003-4 R4, R4.2, and R 4.3 have been moved to CIP 011 R1. CIP-003-4, Requirement R4.1 was moved to the definition of BES Cyber System Information.

Reference to prior version: (Part 1.1) CIP-003-3, R4; CIP-003-3, R4.2

Change Rationale: (Part 1.1)

The SDT removed the explicit requirement for classification as there was no requirement to have multiple levels of protection (e.g., confidential, public, internal use only, etc.) This modification does not prevent having multiple levels of classification, allowing more flexibility for entities to incorporate the CIP information protection program into their normal business.

Reference to prior version: (Part 1.2) CIP-003-3, R4

Change Rationale: (Part 1.2)

The SDT changed the language from "protect" information to "Procedures for protecting and securely handling" to clarify the protection that is required.

Rationale for R2:

The intent of the BES Cyber Asset reuse and disposal process is to prevent the unauthorized dissemination of BES Cyber System Information upon reuse or disposal.

Reference to prior version: (Part 2.1) CIP-007-3, R7.2

Change Rationale: (Part 2.1)

Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.

Reference to prior version: (Part 2.2) CIP-007-3, R7.1

Change Rationale: (Part 2.2)

Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.

The SDT also removed the requirement explicitly requiring records of destruction/redeployment as this was seen as demonstration of the existing requirement and not a requirement in and of itself.

Version History

Version	Date	Action	Change Tracking
1	11/26/12	Adopted by the NERC Board of Trustees.	Developed to define the information protection requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706.
1	11/22/13	FERC Order issued approving CIP-011-1. (Order becomes effective on 2/3/14.)	
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Cyber Security — Information Protection
2. **Number:** CIP-011-1(X)
3. **Purpose:** To prevent unauthorized access to BES Cyber System Information by specifying information protection requirements in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as “Responsible Entities.” For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.
 - 4.1.1 **Balancing Authority**
 - 4.1.2 **Distribution Provider** that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
 - 4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
 - 4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
 - 4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
 - 4.1.2.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
 - 4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
 - 4.1.3 **Generator Operator**
 - 4.1.4 **Generator Owner**
 - 4.1.5 **Interchange Coordinator or Interchange Authority**
 - 4.1.6 **Reliability Coordinator**

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3 Exemptions: The following are exempt from Standard CIP-011-1(X):

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1(X) identification and categorization processes.

5. Effective Dates:

1. **24 Months Minimum** – CIP-011-1(X) shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.

2. In those jurisdictions where no regulatory approval is required, CIP-011-1(X) shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

Standard CIP-011-1(X) exists as part of a suite of CIP Standards related to cyber security. CIP-002-5.1(X) requires the initial identification and categorization of BES Cyber Systems. CIP-003-5(X), CIP-004-5.1(X), CIP-005-5(X), CIP-006-5(X), CIP-007-5(X), CIP-008-5(X), CIP-009-5(X), CIP-010-1(X), and CIP-011-1(X) require a minimum level of organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards*.

Most requirements open with, *“Each Responsible Entity shall implement one or more documented [processes, plan, etc] that include the applicable items in [Table Reference].”* The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The SDT has incorporated within this standard a recognition that certain requirements should not focus on individual instances of failure as a sole basis for violating the standard. In particular, the SDT has incorporated an approach to empower and enable the industry to identify, assess, and correct deficiencies in the implementation of certain requirements. The intent is to change the basis of a violation in those requirements so that they are not focused on *whether* there is a deficiency, but on identifying, assessing, and correcting deficiencies. It is presented in those requirements by modifying “implement” as follows:

Each Responsible Entity shall implement, **in a manner that identifies, assesses, and corrects deficiencies, . . .**

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements.

An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table. The documented processes themselves are not required to include the “. . . identifies, assesses, and corrects deficiencies, . . .” elements described in the preceding paragraph, as those aspects are related to the manner of implementation of the documented processes and could be accomplished through other controls or compliance management activities.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization’s overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an “or,” and numbered items are items that are linked with an “and.”

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

“Applicable Systems” Columns in Tables:

Each table has an “Applicable Systems” column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept

from the National Institute of Standards and Technology (“NIST”) Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the “Applicable Systems” column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1(X) identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)**– Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System

B. Requirements and Measures

- R1.** Each Responsible Entity shall implement, in a manner that identifies, assesses, and corrects deficiencies, one or more documented information protection program(s) that collectively includes each of the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection*. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M1.** Evidence for the information protection program must include the applicable requirement parts in *CIP-011-1(X) Table R1 – Information Protection* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-1(X) Table R1 – Information Protection

Part	Applicable Systems	Requirements	Measures
1.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Method(s) to identify information that meets the definition of BES Cyber System Information.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Documented method to identify BES Cyber System Information from entity’s information protection program; or • Indications on information (e.g., labels or classification) that identify BES Cyber System Information as designated in the entity’s information protection program; or • Training materials that provide personnel with sufficient knowledge to recognize BES Cyber System Information; or • Repository or electronic and physical location designated for housing BES Cyber System Information in the entity’s information protection program.

CIP-011-1(X) Table R1 – Information Protection

Part	Applicable Systems	Requirement	Measure
1.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; and 2. PACS 	<p>Procedure(s) for protecting and securely handling BES Cyber System Information, including storage, transit, and use.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Procedures for protecting and securely handling, which include topics such as storage, security during transit, and use of BES Cyber System Information; or • Records indicating that BES Cyber System Information is handled in a manner consistent with the entity’s documented procedure(s).

- R2.** Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal*. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning].
- M2.** Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal			
Part	Applicable Systems	Requirements	Measures
2.1	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Prior to the release for reuse of applicable Cyber Assets that contain BES Cyber System Information (except for reuse within other systems identified in the “Applicable Systems” column), the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Records tracking sanitization actions taken to prevent unauthorized retrieval of BES Cyber System Information such as clearing, purging, or destroying; or • Records tracking actions such as encrypting, retaining in the Physical Security Perimeter or other methods used to prevent unauthorized retrieval of BES Cyber System Information.

CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal			
Part	Applicable Systems	Requirements	Measures
2.2	<p>High Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA <p>Medium Impact BES Cyber Systems and their associated:</p> <ol style="list-style-type: none"> 1. EACMS; 2. PACS; and 3. PCA 	<p>Prior to the disposal of applicable Cyber Assets that contain BES Cyber System Information, the Responsible Entity shall take action to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset or destroy the data storage media.</p>	<p>Examples of acceptable evidence include, but are not limited to:</p> <ul style="list-style-type: none"> • Records that indicate that data storage media was destroyed prior to the disposal of an applicable Cyber Asset; or • Records of actions taken to prevent unauthorized retrieval of BES Cyber System Information prior to the disposal of an applicable Cyber Asset.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information:

- None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-011-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Medium	N/A		<p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.1)</p> <p>OR</p> <p>The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more methods to identify BES Cyber System Information but did not identify,</p>	<p>The Responsible Entity has not documented or implemented a BES Cyber System Information protection program (R1).</p>

R #	Time Horizon	VRF	Violation Severity Levels (CIP-011-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					assess, or correct the deficiencies. (1.1) OR The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information and has identified deficiencies but did not assess or correct the deficiencies. (1.2) OR The Responsible Entity has implemented a BES Cyber System Information protection program which includes one or more procedures for protection and secure handling BES Cyber System Information	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-011-1(X))			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					but did not identify, assess, or correct the deficiencies. (1.2)	
R2	Operations Planning	Lower	N/A	The Responsible Entity implemented one or more documented processes but did not include processes for reuse as to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.1)	The Responsible Entity implemented one or more documented processes but did not include disposal or media destruction processes to prevent the unauthorized retrieval of BES Cyber System Information from the BES Cyber Asset. (2.2)	The Responsible Entity has not documented or implemented any processes for applicable requirement parts in CIP-011-1(X) Table R2 – BES Cyber Asset Reuse and Disposal. (R2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section “4. Applicability” of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section “4.1. Functional Entities” is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1(X)'s categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Responsible Entities are free to utilize existing change management and asset management systems. However, the information contained within those systems must be evaluated, as the information protection requirements still apply.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

This requirement mandates that BES Cyber System Information be identified. The Responsible Entity has flexibility in determining how to implement the requirement. The Responsible Entity should explain the method for identifying the BES Cyber System Information in their information protection program. For example, the Responsible Entity may decide to mark or label the documents. Identifying separate classifications of BES Cyber System Information is not specifically required. However, a Responsible Entity maintains the flexibility to do so if they desire. As long as the Responsible Entity's information protection program includes all applicable items, additional classification levels (e.g., confidential, public, internal use only, etc.) can be created that go above and beyond the requirements. If the entity chooses to use classifications, then the types of classifications used by the entity and any associated labeling should be documented in the entity's BES Cyber System Information Program.

The Responsible Entity may store all of the information about BES Cyber Systems in a separate repository or location (physical and/or electronic) with access control implemented. For example, the Responsible Entity's program could document that all information stored in an identified repository is considered BES Cyber System Information, the program may state that all information contained in an identified section of a specific repository is considered BES Cyber System Information, or the program may document that all hard copies of information are stored in a secured area of the building. Additional methods for implementing the requirement are suggested in the measures section. However, the methods listed in measures are not meant to be an exhaustive list of methods that the entity may choose to utilize for the identification of BES Cyber System Information.

The SDT does not intend that this requirement cover publicly available information, such as vendor manuals that are available via public websites or information that is deemed to be publicly releasable.

Information protection pertains to both digital and hardcopy information. R1.2 requires one or more procedures for the protection and secure handling BES Cyber System Information, including storage, transit, and use.

The entity's written Information Protection Program should explain how the entity handles aspects of information protection including specifying how BES Cyber System Information is to be securely handled during transit in order to protect against unauthorized access, misuse, or corruption and to protect confidentiality of the communicated BES Cyber System Information. For example, the use of a third-party communication service provider instead of organization-owned infrastructure may warrant the use of encryption to prevent unauthorized disclosure of information during transmission. The entity may choose to establish a trusted communications path for transit of BES Cyber System Information. The trusted communications path would utilize a logon or other security measures to provide secure handling during transit. The entity may employ alternative physical protective measures, such as the use of a courier or locked container for transmission of information. It is not the intent of this standard to mandate the use of one particular format for secure handling during transit.

A good Information Protection Program will document the circumstances under which BES Cyber System Information can be shared with or used by third parties. The organization should distribute or share information on a need-to-know basis. For example, the entity may specify that a confidentiality agreement, non-disclosure arrangement, contract, or written agreement of some kind concerning the handling of information must be in place between the entity and the third party. The entity's Information Protection Program should specify circumstances for sharing of BES Cyber System Information with and use by third parties, for example, use of a non-disclosure agreement. The entity should then follow their documented program. These requirements do not mandate one specific type of arrangement.

Requirement R2:

This requirement allows for BES Cyber Systems to be removed from service and analyzed with their media intact, as that should not constitute a release for reuse. However, following the

analysis, if the media is to be reused outside of a BES Cyber System or disposed of, the entity must take action to prevent the unauthorized retrieval of BES Cyber System Information from the media.

The justification for this requirement is pre-existing from previous versions of CIP and is also documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking.

If an applicable Cyber Asset is removed from the Physical Security Perimeter prior to action taken to prevent the unauthorized retrieval of BES Cyber System Information or destroying the data storage media, the responsible entity should maintain documentation that identifies the custodian for the data storage media while the data storage media is outside of the Physical Security Perimeter prior to actions taken by the entity as required in R2.

Media sanitization is the process used to remove information from system media such that reasonable assurance exists that the information cannot be retrieved or reconstructed. Media sanitization is generally classified into four categories: Disposal, clearing, purging, and destroying. For the purposes of this requirement, disposal by itself, with the exception of certain special circumstances, such as the use of strong encryption on a drive used in a SAN or other media, should never be considered acceptable. The use of clearing techniques may provide a suitable method of sanitization for media that is to be reused, whereas purging techniques may be more appropriate for media that is ready for disposal.

The following information from NIST SP800-88 provides additional guidance concerning the types of actions that an entity might take to prevent the unauthorized retrieval of BES Cyber System Information from the Cyber Asset data storage media:

Clear: One method to sanitize media is to use software or hardware products to overwrite storage space on the media with non-sensitive data. This process may include overwriting not only the logical storage location of a file(s) (e.g., file allocation table) but also may include all addressable locations. The security goal of the overwriting process is to replace written data with random data. Overwriting cannot be used for media that are damaged or not rewriteable. The media type and size may also influence whether overwriting is a suitable sanitization method [SP 800-36].

Purge: Degaussing and executing the firmware Secure Erase command (for ATA drives only) are acceptable methods for purging. Degaussing is exposing the magnetic media to a strong magnetic field in order to disrupt the recorded magnetic domains. A degausser is a device that generates a magnetic field used to sanitize magnetic media. Degaussers are rated based on the type (i.e., low energy or high energy) of magnetic media they can purge. Degaussers operate using either a strong permanent magnet or an electromagnetic coil. Degaussing can be an effective method for purging damaged or inoperative media, for purging media with exceptionally large storage capacities, or for quickly purging diskettes. [SP 800-36] Executing the firmware Secure Erase command (for ATA drives only) and degaussing are examples of acceptable methods for purging.

Degaussing of any hard drive assembly usually destroys the drive as the firmware that manages the device is also destroyed.

Destroy: There are many different types, techniques, and procedures for media destruction. Disintegration, Pulverization, Melting, and Incineration are sanitization methods designed to completely destroy the media. They are typically carried out at an outsourced metal destruction or licensed incineration facility with the specific capabilities to perform these activities effectively, securely, and safely. Optical mass storage media, including compact disks (CD, CD-RW, CD-R, CD-ROM), optical disks (DVD), and MO disks, must be destroyed by pulverizing, crosscut shredding or burning. In some cases such as networking equipment, it may be necessary to contact the manufacturer for proper sanitization procedure.

It is critical that an organization maintain a record of its sanitization actions to prevent unauthorized retrieval of BES Cyber System Information. Entities are strongly encouraged to review NIST SP800-88 for guidance on how to develop acceptable media sanitization processes.

Rationale:

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:

The SDT's intent of the information protection program is to prevent unauthorized access to BES Cyber System Information.

Summary of Changes: CIP 003-4 R4, R4.2, and R 4.3 have been moved to CIP 011 R1. CIP-003-4, Requirement R4.1 was moved to the definition of BES Cyber System Information.

Reference to prior version: (Part 1.1) CIP-003-3, R4; CIP-003-3, R4.2

Change Rationale: (Part 1.1)

The SDT removed the explicit requirement for classification as there was no requirement to have multiple levels of protection (e.g., confidential, public, internal use only, etc.) This modification does not prevent having multiple levels of classification, allowing more flexibility for entities to incorporate the CIP information protection program into their normal business.

Reference to prior version: (Part 1.2) CIP-003-3, R4

Change Rationale: (Part 1.2)

The SDT changed the language from "protect" information to "Procedures for protecting and securely handling" to clarify the protection that is required.

Rationale for R2:

The intent of the BES Cyber Asset reuse and disposal process is to prevent the unauthorized dissemination of BES Cyber System Information upon reuse or disposal.

Reference to prior version: (Part 2.1) CIP-007-3, R7.2

Change Rationale: (Part 2.1)

Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.

Reference to prior version: (Part 2.2) CIP-007-3, R7.1

Change Rationale: (Part 2.2)

Consistent with FERC Order No. 706, Paragraph 631, the SDT clarified that the goal was to prevent the unauthorized retrieval of information from the media, removing the word “erase” since, depending on the media itself, erasure may not be sufficient to meet this goal.

The SDT also removed the requirement explicitly requiring records of destruction/redeployment as this was seen as demonstration of the existing requirement and not a requirement in and of itself.

Version History

Version	Date	Action	Change Tracking
1	11/26/12	Adopted by the NERC Board of Trustees.	Developed to define the information protection requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706.
1	11/22/13	FERC Order issued approving CIP-011-1. (Order becomes effective on 2/3/14.)	
<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2(X)
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
 - 4.1.1. Reliability Coordinator
 - 4.1.2. Balancing Authority
 - 4.1.3. Transmission Owner
 - 4.1.4. Transmission Operator
 - 4.1.5. Generator Owner
 - 4.1.6. Generator Operator
 - 4.1.7. Distribution Provider

5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date 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.

6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2(X) Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2(X) Attachment 1 and in accordance with the entity responsible for reporting.

- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2(X) Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*]
[*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2 Evidence Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment	Medium	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Medium	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p>

D. Variances

None.

E. Interpretations

None.

F. References

Guideline and Technical Basis (attached)

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.
Damage or destruction of a Facility	BA, TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action.
Physical threats to a Facility	BA, TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.

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Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Physical threats to a BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.
BES Emergency requiring public appeal for load reduction	Initiating entity is responsible for reporting	Public appeal for load reduction event.
BES Emergency requiring system-wide voltage reduction	Initiating entity is responsible for reporting	System wide voltage reduction of 3% or more.
BES Emergency requiring manual firm load shedding	Initiating entity is responsible for reporting	Manual firm load shedding ≥ 100 MW.
BES Emergency resulting in automatic firm load shedding	DP, TOP	Automatic firm load shedding ≥ 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or RAS).
Voltage deviation on a Facility	TOP	Observed within its area a voltage deviation of $\pm 10\%$ of nominal voltage sustained for ≥ 15 continuous minutes.

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Event Type	Entity with Reporting Responsibility	Threshold for Reporting
IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)	RC	Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
Loss of firm load	BA, TOP, DP	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand $\geq 3,000$ OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA, GOP	Total generation loss, within one minute, of : $\geq 2,000$ MW for entities in the Eastern or Western Interconnection OR $\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

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Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of voice communication capability	RC, BA, TOP	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.
Complete loss of monitoring capability	RC, BA, TOP	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form	
<p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780.</p>	
Task	Comments
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:
3.	Did the event originate in your system? Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>
4.	Event Identification and Description:
(Check applicable box) <input type="checkbox"/> Damage or destruction of a Facility <input type="checkbox"/> Physical Threat to a Facility <input type="checkbox"/> Physical Threat to a control center <input type="checkbox"/> BES Emergency: <input type="checkbox"/> public appeal for load reduction <input type="checkbox"/> system-wide voltage reduction <input type="checkbox"/> manual firm load shedding <input type="checkbox"/> automatic firm load shedding <input type="checkbox"/> Voltage deviation on a Facility <input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) <input type="checkbox"/> Loss of firm load <input type="checkbox"/> System separation <input type="checkbox"/> Generation loss <input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply) <input type="checkbox"/> Transmission loss <input type="checkbox"/> unplanned control center evacuation <input type="checkbox"/> Complete loss of voice communication capability <input type="checkbox"/> Complete loss of monitoring capability	Written description (optional):

Guideline and Technical Basis

Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

EOP-004-2(X) — Event Reporting

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

Data Gathering

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2(X) specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2(X) may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

Law Enforcement Reporting

The reliability objective of EOP-004-2(X) is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Present expectations of the industry under CIP-001-1a:

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

Coordination of Local and State Law Enforcement Agencies with the FBI

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

Coordination of Local and Provincial Law Enforcement Agencies with the RCMP

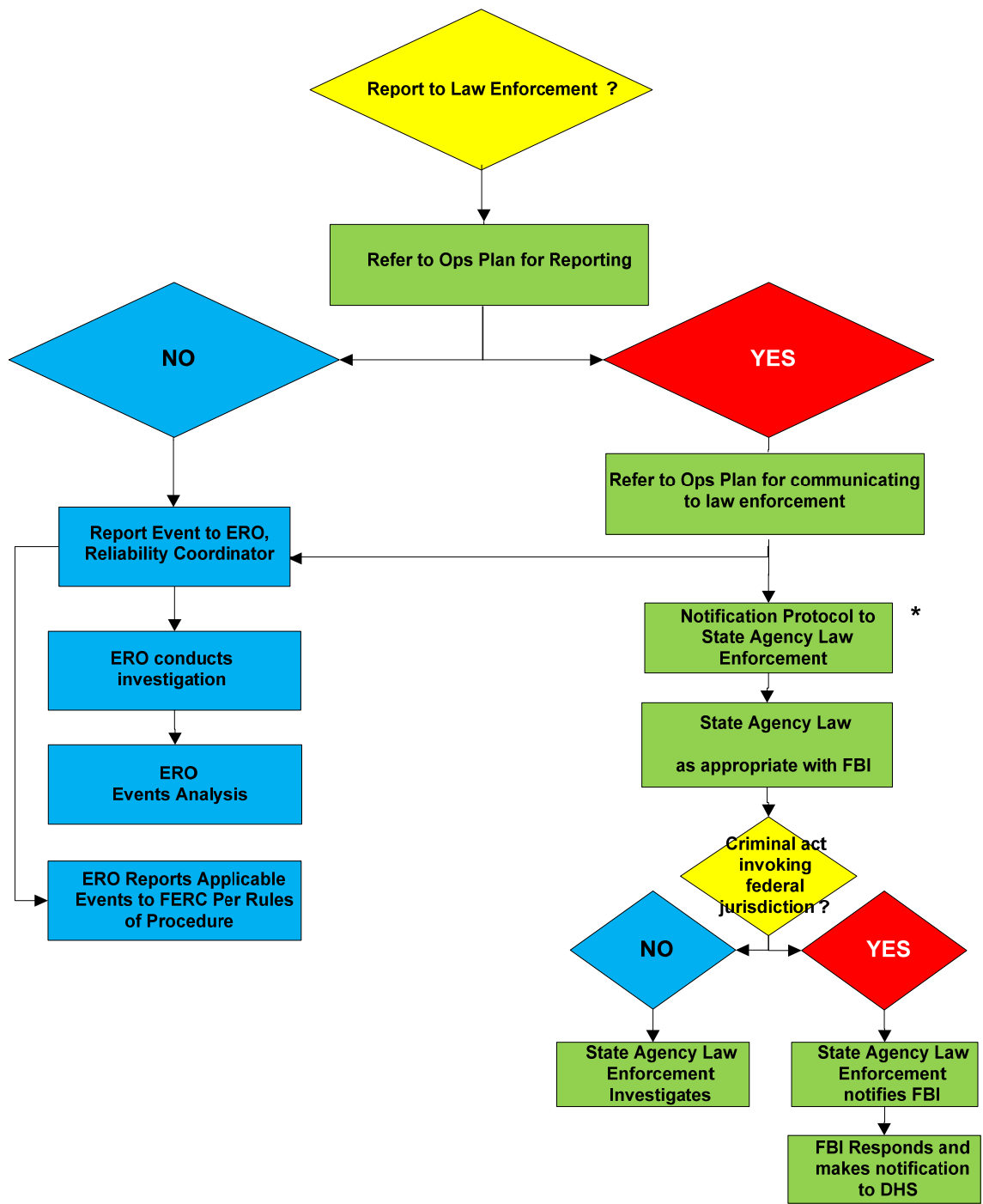
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

A Reporting Process Solution – EOP-004

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“ . . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

Potential Uses of Reportable Information

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Collection of Reportable Information or “One stop shopping”

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

Rationale for R2:

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2(X) Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

Rationale for R3:

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

Rationale for EOP-004 Attachment 1:

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
2(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2(X)
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
 - 4.1.1. Reliability Coordinator
 - 4.1.2. Balancing Authority
 - 4.1.3. Transmission Owner
 - 4.1.4. Transmission Operator
 - 4.1.5. Generator Owner
 - 4.1.6. Generator Operator
 - 4.1.7. Distribution Provider

5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date 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.

6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2(X) Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2(X) Attachment 1 and in accordance with the entity responsible for reporting.
- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*
- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2(X) Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2 Evidence Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment	Medium	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Medium	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p>

D. Variances

None.

E. Interpretations

None.

F. References

Guideline and Technical Basis (attached)

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.
Damage or destruction of a Facility	BA, TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action.
Physical threats to a Facility	BA, TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.

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Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Physical threats to a BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.
BES Emergency requiring public appeal for load reduction	Initiating entity is responsible for reporting	Public appeal for load reduction event.
BES Emergency requiring system-wide voltage reduction	Initiating entity is responsible for reporting	System wide voltage reduction of 3% or more.
BES Emergency requiring manual firm load shedding	Initiating entity is responsible for reporting	Manual firm load shedding \geq 100 MW.
BES Emergency resulting in automatic firm load shedding	DP, TOP	Automatic firm load shedding \geq 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or SPS /RAS).
Voltage deviation on a Facility	TOP	Observed within its area a voltage deviation of \pm 10% of nominal voltage sustained for \geq 15 continuous minutes.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)	RC	Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
Loss of firm load	BA, TOP, DP	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand $\geq 3,000$ OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA, GOP	Total generation loss, within one minute, of : $\geq 2,000$ MW for entities in the Eastern or Western Interconnection OR $\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of voice communication capability	RC, BA, TOP	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.
Complete loss of monitoring capability	RC, BA, TOP	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form	
<p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780.</p>	
Task	Comments
1.	<p>Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):</p>
2.	<p>Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:</p>
3.	<p>Did the event originate in your system? Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/></p>
4.	<p style="text-align: center;">Event Identification and Description:</p> <p>(Check applicable box)</p> <p><input type="checkbox"/> Damage or destruction of a Facility</p> <p><input type="checkbox"/> Physical Threat to a Facility</p> <p><input type="checkbox"/> Physical Threat to a control center</p> <p><input type="checkbox"/> BES Emergency:</p> <p style="padding-left: 20px;"><input type="checkbox"/> public appeal for load reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> system-wide voltage reduction</p> <p style="padding-left: 20px;"><input type="checkbox"/> manual firm load shedding</p> <p style="padding-left: 20px;"><input type="checkbox"/> automatic firm load shedding</p> <p><input type="checkbox"/> Voltage deviation on a Facility</p> <p><input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)</p> <p><input type="checkbox"/> Loss of firm load</p> <p><input type="checkbox"/> System separation</p> <p><input type="checkbox"/> Generation loss</p> <p><input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply)</p> <p><input type="checkbox"/> Transmission loss</p> <p><input type="checkbox"/> unplanned control center evacuation</p> <p><input type="checkbox"/> Complete loss of voice communication capability</p> <p><input type="checkbox"/> Complete loss of monitoring capability</p> <p style="text-align: right;">Written description (optional):</p>

Guideline and Technical Basis

Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

EOP-004-2(X) — Event Reporting

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

Data Gathering

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2(X) specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2(X) may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

Law Enforcement Reporting

The reliability objective of EOP-004-2(X) is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Present expectations of the industry under CIP-001-1a:

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

Coordination of Local and State Law Enforcement Agencies with the FBI

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

Coordination of Local and Provincial Law Enforcement Agencies with the RCMP

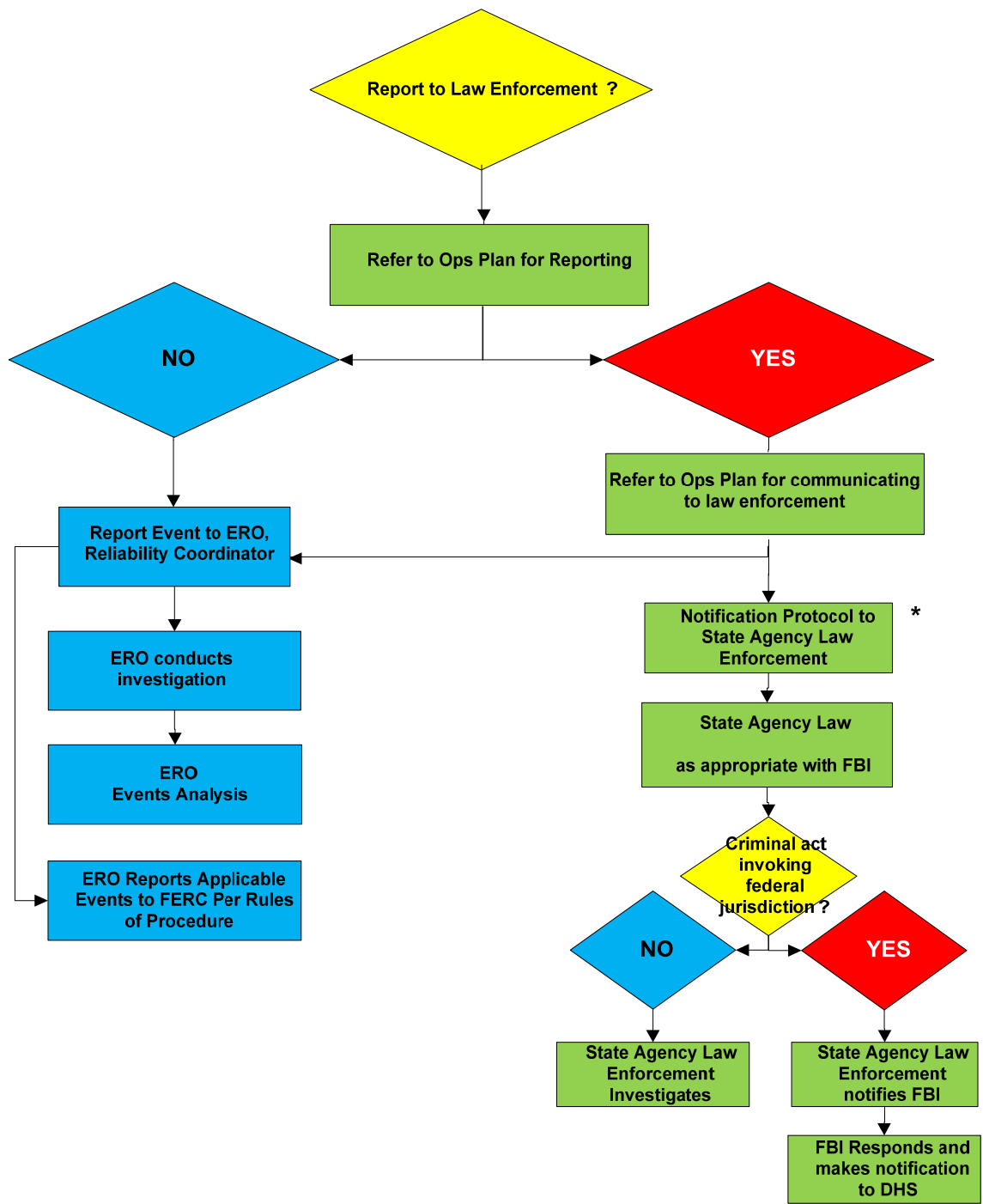
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

A Reporting Process Solution – EOP-004

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement Enforcement

Entity Experiencing An Event in Attachment 1



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

Potential Uses of Reportable Information

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Collection of Reportable Information or “One stop shopping”

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

Rationale for R2:

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2(X) Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

Rationale for R3:

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

Rationale for EOP-004 Attachment 1:

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	
<u>2(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-2.1(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
 - 4.1. Planning Authority
5. **Effective Date:** April 19, 2010

B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
 - R1.1. Be applicable for developing SOLs used in the planning horizon.
 - R1.2. State that SOLs shall not exceed associated Facility Ratings.
 - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
 - R2.1. In the pre-contingency state and with all Facilities in service, 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. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
 - R2.2. Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the 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.
 - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
 - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
 - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
 - R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
 - R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

¹ The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
 - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
 - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the 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.
 - R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
 - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
 - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
 - R3.2.** Selection of applicable Contingencies.
 - R3.3.** Level of detail of system models used to determine SOLs.
 - R3.4.** Allowed uses of Remedial Action Schemes.
 - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
 - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v .
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
 - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
 - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
 - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.
(Retirement approved by FERC effective January 21, 2014.)

1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

- 2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
 - 2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
 - 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
 - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
 - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
 - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6	The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

Requirement	Lower	Moderate	High	Severe
		<p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>	<p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>	<p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>
R5	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

Requirement	Lower	Moderate	High	Severe
<p>(Retirement approved by FERC effective January 21, 2014.)</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p>

E. Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
 - 1.1. As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
 - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
 - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
 - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
 - 1.1.4 The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
 - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
 - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
 - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
 - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
 - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
 - 1.2.2 Cascading does not occur.
 - 1.2.3 Uncontrolled separation of the system does not occur.
 - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
 - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
 - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
- 1.3.1** Cascading does not occur.
- 1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1 st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

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2.1	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
2.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** System Operating Limits Methodology for the Planning Horizon
2. **Number:** FAC-010-2.1(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
 - 4.1. Planning Authority
5. **Effective Date:** April 19, 2010

B. Requirements

- R1. The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
 - R1.1. Be applicable for developing SOLs used in the planning horizon.
 - R1.2. State that SOLs shall not exceed associated Facility Ratings.
 - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
 - R2.1. In the pre-contingency state and with all Facilities in service, 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. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
 - R2.2. Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the 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.
 - R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
 - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
 - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
 - R2.3. Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
 - R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

¹ The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

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- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
 - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
 - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the 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.
 - R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
 - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
 - R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
 - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
 - R3.2.** Selection of applicable Contingencies.
 - R3.3.** Level of detail of system models used to determine SOLs.
 - R3.4.** Allowed uses of ~~Special Protection Systems or~~ Remedial Action ~~Plans~~Schemes.
 - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
 - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v .
 - R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
 - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
 - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
 - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
 - R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (**Retirement approved by FERC effective January 21, 2014.**)

C. Measures

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- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.

(Retirement approved by FERC effective January 21, 2014.)

1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

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- 2.1. Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
 - 2.1.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
 - 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology. (Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
 - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
 - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
 - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

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3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6	The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

Requirement	Lower	Moderate	High	Severe
		<p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>	<p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>	<p>methodology, the changed methodology was provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>
R5	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical	The Planning Authority received documented technical

Standard FAC-010-2.1(X) — System Operating Limits Methodology for the Planning Horizon

Requirement	Lower	Moderate	High	Severe
<p>(Retirement approved by FERC effective January 21, 2014.)</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p>	<p>comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p>

E. Regional Differences

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
 - 1.1.** As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
 - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
 - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
 - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
 - 1.1.4** The failure of a circuit breaker associated with a [Special Protection System Remedial Action Scheme](#) to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
 - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
 - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
 - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
 - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
 - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
 - 1.2.2** Cascading does not occur.
 - 1.2.3** Uncontrolled separation of the system does not occur.
 - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
 - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
 - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
 - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1 st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
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2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

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2.1	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
<u>2.1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

- 1. Title:** System Operating Limits Methodology for the Operations Horizon
- 2. Number:** FAC-011-2(X)
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
 - 4.1.** Reliability Coordinator
- 5. Effective Date:** April 29, 2009

B. Requirements

- R1.** The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
 - R1.1.** Be applicable for developing SOLs used in the operations horizon.
 - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
 - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The 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. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
 - R2.2.** Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the 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.
 - R2.2.1.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
 - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
 - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
 - R2.3.** In determining the system's response to a single Contingency, the following shall be acceptable:

¹ The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
- R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
- R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator’s methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
 - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
 - R3.2.** Selection of applicable Contingencies
 - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
 - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
 - R3.4.** Level of detail of system models used to determine SOLs.
 - R3.5.** Allowed uses of Remedial Action Schemes.
 - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
 - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
 - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
 - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator’s Reliability Coordinator Area.
 - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

- 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.
(Retirement approved by FERC effective January 21, 2014.)
 - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
 - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
- 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
 - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
 - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology
(Retirement approved by FERC effective January 21, 2014.)
 - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
 - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
 - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
 - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
 - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
 - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.
R3.6	N/A	N/A	N/A	N/A
R4	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3

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Requirement	Lower	Moderate	High	Severe
	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>
<p>R5 (Retirement approved by FERC effective January 21, 2014.)</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p>

Regional Differences

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
 - 1.1.** As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
 - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
 - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
 - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
 - 1.1.4** The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
 - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
 - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
 - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
 - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
 - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
 - 1.2.2** Cascading does not occur.
 - 1.2.3** Uncontrolled separation of the system does not occur.
 - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
 - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
 - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
 - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
2(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-2(X)
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability**
 - 4.1. Reliability Coordinator
5. **Effective Date:** April 29, 2009

B. Requirements

- R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
 - R1.1. Be applicable for developing SOLs used in the operations horizon.
 - R1.2. State that SOLs shall not exceed associated Facility Ratings.
 - R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2. The 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. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
 - R2.2. Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the 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.
 - R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
 - R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.
 - R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
 - R2.3. In determining the system's response to a single Contingency, the following shall be acceptable:

¹ The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

- R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.
 - R2.3.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies
 - R2.3.3.** System reconfiguration through manual or automatic control or protection actions.
- R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
- R3.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
 - R3.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)
 - R3.2.** Selection of applicable Contingencies
 - R3.3.** A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.
 - R3.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
 - R3.4.** Level of detail of system models used to determine SOLs.
 - R3.5.** Allowed uses of ~~Special Protection Systems~~ or Remedial Action ~~Plans~~Schemes.
 - R3.6.** Anticipated transmission system configuration, generation dispatch and Load level
 - R3.7.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v .
- R4.** The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following:
 - R4.1.** Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.
 - R4.2.** Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.
 - R4.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Reliability Coordinator shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2.** The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3.** If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

- 1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses.
(Retirement approved by FERC effective January 21, 2014.)
 - 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
 - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
2. **Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
 - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
 - 2.1.2 No evidence of responses to a recipient's comments on the SOL Methodology
(Retirement approved by FERC effective January 21, 2014.)
 - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
 - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
 - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
 - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
 - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
 - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.
R3.6	N/A	N/A	N/A	N/A
R4	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3

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Requirement	Lower	Moderate	High	Severe
	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>
<p>R5 (Retirement approved by FERC effective January 21, 2014.)</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p>

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
 - 1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
 - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
 - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
 - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
 - 1.1.4 The failure of a circuit breaker associated with a [Special Protection System Remedial Action Scheme](#) to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
 - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
 - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
 - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
 - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
 - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
 - 1.2.2 Cascading does not occur.
 - 1.2.3 Uncontrolled separation of the system does not occur.
 - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
 - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
 - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
 - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
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2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
2 (X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1a(X)
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
 - 4.3. Transmission Operators.
 - 4.4. Transmission Service Providers.
 - 4.5. Generator Operators.
 - 4.6. Load-Serving Entities.
 - 4.7. Purchasing-Selling Entities.

5. **Effective Date:**

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
 - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.
 - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.4. System real and reactive reserves (actual versus required).
 - R1.5. Capacity and energy adequacy conditions.
 - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

C. Measures

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance

outages with Transmission Operators, Balancing Authorities and Generator Operators.
(Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.	The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.	The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.	The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.
R1.1	The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Remedial Action Schemes) and system loading.	N/A	N/A	N/A
R1.2	The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.	N/A	N/A	N/A

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R1.3	The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.	N/A	N/A	N/A
R1.4	The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).	N/A	N/A	N/A
R1.5	The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.	N/A	N/A	N/A
R1.6	The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.	N/A	N/A	N/A
R1.7	The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.	N/A	N/A	N/A
R1.8	The Reliability Coordinator failed to monitor planned generation dispatches.	N/A	N/A	N/A
R1.9	The Reliability Coordinator failed to monitor planned transmission or generation outages.	N/A	N/A	N/A

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R1.10	The Reliability Coordinator failed to monitor contingency events.	N/A	N/A	N/A
R2	N/A	The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.	The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.
R3	N/A	N/A	The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.	The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.
R4	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R5	N/A	N/A	The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.	The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R6	N/A	<p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p>	<p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p>	<p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p>
R7	N/A	N/A	N/A	<p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R8	N/A	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.	The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.
R9	N/A	N/A	N/A	The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any degradation or potential failure to operate as expected.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R10	N/A	N/A	N/A	The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.
R11	N/A	N/A	N/A	The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
R12	N/A	The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	N/A	The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17 Retired M2 and M3; modified M9 and M12; retired M13 Made conforming changes to data retention Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Retired VSLs associated with R2, R3, R5, R16 and R17; Modified VSLs associated with R9 and R13, and R14	Revised
2	November 1, 2006	Approved by the Board of Trustees	
2	January 1, 2007	Effective Date	
2a	November 5, 2009	Approved by the Board of Trustees	
3	October 17, 2008	Approved by the Board of Trustees	
3	March 17, 2011	Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)	
3a	April 21, 2011	Added FERC approved Interpretation	
3.1a	March 8, 2012	Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)	Errata
3.1a	September 13, 2012	FERC approved	Errata

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

3.1a	February 28, 2014	Updated VSLs based on June 24, 2013 approval.	
3.1a(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Appendix 1

Requirement Number and Text of Requirement
<p>TOP-005-1 Requirement R3</p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0(X) “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p style="text-align: center;"><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p>IRO-005-1 Requirement R12¹</p> <p>R12. Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p>PRC-012-0(X) Requirements R1 and R1.3</p> <p>R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;">R1.3. Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p>
Background Information for Interpretation
<p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>

¹ In the current version of the Standard (IRO-005-3a)(X), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. **Title:** Reliability Coordination — Current Day Operations
2. **Number:** IRO-005-3.1a(X)
3. **Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
 - 4.3. Transmission Operators.
 - 4.4. Transmission Service Providers.
 - 4.5. Generator Operators.
 - 4.6. Load-Serving Entities.
 - 4.7. Purchasing-Selling Entities.

5. **Effective Date:**

In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

- R1. Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
 - R1.1. Current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and ~~Special Protection System~~ Remedial Action Schemes) and system loading.
 - R1.2. Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.3. Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.4. System real and reactive reserves (actual versus required).
 - R1.5. Capacity and energy adequacy conditions.
 - R1.6. Current ACE for all its Balancing Authorities.

- R1.7.** Current local or Transmission Loading Relief procedures in effect.
- R1.8.** Planned generation dispatches.
- R1.9.** Planned transmission or generation outages.
- R1.10.** Contingency events.
- R2.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R3.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R4.** The Reliability Coordinator shall disseminate information within its Reliability Coordinator Area, as required.
- R5.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R6.** The Reliability Coordinator shall coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R7.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R8.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R9.** Whenever a ~~Special Protection System~~Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that ~~Special Protection System~~Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the ~~Special Protection System~~Remedial Action Scheme including any degradation or potential failure to operate as expected.
- R10.** In instances where there is a difference in derived limits, the Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.

- R11.** The Transmission Service Provider shall respect SOLs and IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
- R12.** Each Reliability Coordinator who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area shall issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem has been mitigated.

C. Measures

- M1.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, Energy Management System description documents, computer printouts, a prepared report specifically detailing compliance to each of the bullets in Requirement 1, EMS availability, SCADA data collection system communications performance or equivalent evidence that will be used to confirm that it monitors the Reliability Coordinator Area parameters specified in Requirements 1.1 through 1.9.
- M2.** If one of its Balancing Authorities has insufficient operating reserves, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to computer printouts, operating logs, voice recordings or transcripts of voice recordings, or equivalent evidence that will be used to determine if the Reliability Coordinator directed and, if needed, assisted the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. (Requirement 2 and Requirement 7)
- M3.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it informed Transmission Operators and Balancing Authorities of Geo-Magnetic Disturbance (GMD) forecast information and provided assistance as needed in the development of any required response plans. (Requirement 3)
- M4.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it disseminated information within its Reliability Coordinator Area in accordance with Requirement 4.
- M5.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, computer printouts, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it monitored system frequency and Balancing Authority performance and directed any necessary rebalancing, as specified in Requirement 5 Part 1.
- M6.** The Transmission Operators and Balancing Authorities shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it utilized all resources, including firm load shedding, as directed by its Reliability Coordinator, to relieve an emergent condition. (Requirement 5 Part 2)
- M7.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, operator logs or equivalent evidence that will be used to determine if it

coordinated with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations including the coordination of pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities and Generator Operators. (Requirement 6 Part 1)

- M8.** If a large Area Control Error has occurred, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, Hot Line recordings, electronic communications or equivalent evidence that will be used to determine if it identified sources of the Area Control Errors, and initiated corrective actions with the appropriate Balancing Authority if the problem was within the Reliability Coordinator's Area (Requirement 8 Part 1)
- M9.** If a ~~Special Protection System~~Remedial Action Scheme is armed and that system could have had an inter-area impact, the Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, agreements with their Transmission Operators, procedural documents, operator logs, computer analysis, training modules, training records or equivalent evidence that will be used to confirm that it was aware of the impact of that ~~Special Protection System~~Remedial Action Scheme on inter-area flows. (Requirement 9)
- M10.** If there is an instance where there is a disagreement on a derived limit, the Transmission Operator, Balancing Authority, Generator Operator, Load-serving Entity, Purchasing-selling Entity and Transmission Service Provider involved in the disagreement shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications or equivalent evidence that will be used to determine if it operated to the most limiting parameter. (Requirement 10)
- M11.** The Transmission Service Providers shall have and provide upon request evidence that could include, but is not limited to, procedural documents, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it respected the SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.(Requirement 11)
- M12.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it issued alerts when it foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area, to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area as specified in Requirement 12 Part 1.
- M13.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that upon receiving information such as an SOL or IROL violation, loss of reactive reserves, etc. it disseminated the information to its impacted Transmission Operators and Balancing Authorities as specified in Requirement 12 Part 2.
- M14.** The Reliability Coordinator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to confirm that it notified all impacted Transmission Operators, Balancing Authorities and Reliability Coordinators when a transmission problem has been mitigated. (Requirement 12 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 9, each Reliability Coordinator shall have its current in-force documents as evidence.

For Measures 2–8 and Measures 12 through 13, the Reliability Coordinator shall keep 90 days of historical data (evidence).

For Measure 6, the Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence).

For Measure 10, the Transmission Operator, Balancing Authority, and Transmission Service Provider shall keep 90 days of historical data (evidence).

For Measure 11, the Transmission Service Provider shall keep 90 days of historical data (evidence).

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Reliability Coordinator failed to monitor one (1) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.	The Reliability Coordinator failed to monitor two (2) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.	The Reliability Coordinator failed to monitor three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.	The Reliability Coordinator failed to monitor more than three (3) of the elements listed in IRO-005-3.1a(X) R1.1 through R1.10.
R1.1	The Reliability Coordinator failed to monitor the current status of Bulk Electric System elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection System Remedial Action Schemes) and system loading.	N/A	N/A	N/A
R1.2	The Reliability Coordinator failed to monitor current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.	N/A	N/A	N/A

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R1.3	The Reliability Coordinator failed to monitor current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan’s viability and scope.	N/A	N/A	N/A
R1.4	The Reliability Coordinator failed to monitor system real and reactive reserves (actual versus required).	N/A	N/A	N/A
R1.5	The Reliability Coordinator failed to monitor capacity and energy adequacy conditions.	N/A	N/A	N/A
R1.6	The Reliability Coordinator failed to monitor current ACE for all its Balancing Authorities.	N/A	N/A	N/A
R1.7	The Reliability Coordinator failed to monitor current local or Transmission Loading Relief procedures in effect.	N/A	N/A	N/A
R1.8	The Reliability Coordinator failed to monitor planned generation dispatches.	N/A	N/A	N/A
R1.9	The Reliability Coordinator failed to monitor planned transmission or generation outages.	N/A	N/A	N/A

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R1.10	The Reliability Coordinator failed to monitor contingency events.	N/A	N/A	N/A
R2	N/A	The Reliability Coordinator failed to direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities.	The Reliability Coordinator failed to issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.	The Reliability Coordinator failed to monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves was provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements.
R3	N/A	N/A	The Reliability Coordinator ensured its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information, but failed to assist, when needed, in the development of any required response plans.	The Reliability Coordinator failed to ensure its Transmission Operators and Balancing Authorities were aware of Geo-Magnetic Disturbance (GMD) forecast information.
R4	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate information within its Reliability Coordinator Area, when required.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R5	N/A	N/A	The Reliability Coordinator monitored system frequency and its Balancing Authorities' performance but failed to direct any necessary rebalancing to return to CPS and DCS compliance.	The Reliability Coordinator failed to monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance or the responsible entity failed to utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R6	N/A	<p>The Reliability Coordinator coordinated with Transmission Operators, Balancing Authorities, and Generator Operators, as needed, to develop action plans to mitigate potential or actual SOL, CPS, or DCS violations but failed to implement said plans</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in either the real-time reliability analysis time frame or the next-day reliability analysis</p>	<p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations</p> <p>OR</p> <p>The Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p>	<p>The Reliability Coordinator failed to coordinate with Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations and the Reliability Coordinator failed to coordinate pending generation and transmission maintenance outages with Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real-time and next-day reliability analysis timeframes.</p>
R7	N/A	N/A	N/A	<p>The Reliability Coordinator failed to assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities, when necessary.</p>

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R8	N/A	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange and discussed corrective actions with the appropriate Balancing Authority but failed to direct the Balancing Authority to comply with CPS and DCS.	The Reliability Coordinator identified sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange but failed to discuss corrective actions with the appropriate Balancing Authority.	The Reliability Coordinator failed to identify sources of large Area Control Errors that were contributing to Frequency Error, Time Error, or Inadvertent Interchange.
R9	N/A	N/A	N/A	The Reliability Coordinator failed to be aware of the impact on inter-area flows of an inter-Balancing Authority or inter-Transmission Operator, following the operation of a Special Protection System Remedial Action Scheme that is armed (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), or the Transmission Operator failed to immediately inform the Reliability Coordinator of the status of the Special Protection System Remedial Action Scheme including any degradation or potential failure to operate as expected.

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

Requirement	Lower	Moderate	High	Severe
R10	N/A	N/A	N/A	The responsible entity failed to operate the Bulk Electric System to the most limiting parameter in instances where there was a difference in derived limits.
R11	N/A	N/A	N/A	The Transmission Service Provider failed to respect SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
R12	N/A	The Reliability Coordinator failed to notify all impacted Transmission Operators, Balancing Authorities, when the transmission problem had been mitigated.	N/A	The Reliability Coordinator who foresaw a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area failed to issue an alert to all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, or the receiving Reliability Coordinator failed to disseminate this information to its impacted Transmission Operators and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Retired R2, R3, R5; modified R9, R13 and R14; retired R16 and R17 Retired M2 and M3; modified M9 and M12; retired M13 Made conforming changes to data retention Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs) Retired VSLs associated with R2, R3, R5, R16 and R17; Modified VSLs associated with R9 and R13, and R14	Revised
2	November 1, 2006	Approved by the Board of Trustees	
2	January 1, 2007	Effective Date	
2a	November 5, 2009	Approved by the Board of Trustees	
3	October 17, 2008	Approved by the Board of Trustees	
3	March 17, 2011	Order issued by FERC approving IRO-005-3 (approval effective 5/23/11)	
3a	April 21, 2011	Added FERC approved Interpretation	
3.1a	March 8, 2012	Errata adopted by Standards Committee; (removed outdated references in Measures M10 and M11 to ‘Part 2’ of Requirements R10 and R11)	Errata
3.1a	September 13, 2012	FERC approved	Errata

Standard IRO-005-3.1a(X) — Reliability Coordination — Current Day Operations

3.1a	February 28, 2014	Updated VSLs based on June 24, 2013 approval.	
<u>3.1a(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Appendix 1

Requirement Number and Text of Requirement
<p>TOP-005-1 Requirement R3</p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0(X) “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded special protection system Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p>IRO-005-1 Requirement R12¹</p> <p>R12. Whenever a Special Protection System Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p>PRC-012-0(X) Requirements R1 and R1.3</p> <p>R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a an SPS RAS shall have a documented Regional Reliability Organization RASSPS review procedure to ensure that SPSs RASs comply with Regional criteria and NERC Reliability Standards. The Regional SPS-RAS review procedure shall include:</p> <p style="padding-left: 40px;">R1.3. Requirements to demonstrate that the SPS-RAS shall be designed so that a single SPS RAS component failure, when the SPS-RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p>
<p>Background Information for Interpretation</p> <p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>

¹ In the current version of the Standard (IRO-005-3a)(X), this requirement is R9.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for SPSRAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a SPS RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPSRAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a SPS RAS to operate as designed. If the loss of a communication channel will result in the failure of a SPS RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPSRAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

A. Introduction

1. **Title:** Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
2. **Number:** IRO-014-1(X)
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability**
 - 4.1. Reliability Coordinator
5. **Effective Date:** November 1, 2006

B. Requirements

- R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.
 - R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:
 - R1.1.1. Communications and notifications, including the conditions¹ under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.
 - R1.1.2. Energy and capacity shortages.
 - R1.1.3. Planned or unplanned outage information.
 - R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.
 - R1.1.5. Coordination of information exchange to support reliability assessments.
 - R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.
- R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:
 - R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).
 - R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).
- R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:
 - R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

¹ Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of Remedial Action Schemes, etc.

Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

R3.2. The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

R4.1. Include version control number or date.

R4.2. Include a distribution list.

R4.3. Be reviewed, at least once every three years, and updated if needed.

C. Measures

M1. The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

M1.1 These Operating Procedures, Processes, or Plans shall address:

M1.1.1 Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

M2.1.1 Energy and capacity shortages.

M3.1.1 Planned or unplanned outage information.

M4.1.1 Voltage control, including the coordination of reactive resources for voltage control.

M5.1.1 Coordination of information exchange to support reliability assessments.

M6.1.1 Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

M2.1 Agreed to by all the Reliability Coordinators required to take the indicated action(s).

M2.2 Distributed to all Reliability Coordinators that are required to take the indicated action(s).

M3. The Reliability Coordinator's Operating Procedures, Processes, or Plans developed (for its System Operators' internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

M3.1 Be available to the Reliability Coordinator's System Operators for Real-time use,

M3.2 Include a reference to the associated source document, and

M3.3 Support the agreed-upon actions from the source document.

M4. The Reliability Coordinator's Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator's System Operators.

The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

1.4.1 The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

1.4.2 Evidence of distribution of Operating Procedures, Processes, or Plans.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

2.1.2 The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 Documents required by this standard were not distributed to all entities on the distribution list.

2.2.2 Documents required by this standard were not available for System Operators' Real-time use.

2.2.3 Documents required by this standard do not address all required topics.

2.3. Level 3: Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014-1(X) R1.

2.4. Level 4: Not Applicable.

Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	08/10/05	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Initial capped heading “Definitions of Terms Used in Standard.” 5. Added “periods” to items where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate. 	01/20/06
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard IRO-014-1(X) — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators

A. Introduction

1. **Title:** Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
2. **Number:** IRO-014-1(X)
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability**
 - 4.1. Reliability Coordinator
5. **Effective Date:** November 1, 2006

B. Requirements

- R1. The Reliability Coordinator shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other Reliability Coordinator Areas as well as those developed in coordination with other Reliability Coordinators.
 - R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:
 - R1.1.1. Communications and notifications, including the conditions¹ under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.
 - R1.1.2. Energy and capacity shortages.
 - R1.1.3. Planned or unplanned outage information.
 - R1.1.4. Voltage control, including the coordination of reactive resources for voltage control.
 - R1.1.5. Coordination of information exchange to support reliability assessments.
 - R1.1.6. Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.
- R2. Each Reliability Coordinator's Operating Procedure, Process, or Plan that requires one or more other Reliability Coordinators to take action (e.g., make notifications, exchange information, or coordinate actions) shall be:
 - R2.1. Agreed to by all the Reliability Coordinators required to take the indicated action(s).
 - R2.2. Distributed to all Reliability Coordinators that are required to take the indicated action(s).
- R3. A Reliability Coordinator's Operating Procedures, Processes, or Plans developed to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan shall include:
 - R3.1. A reference to the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

¹ Examples of conditions when one Reliability Coordinator may need to notify another Reliability Coordinator may include (but aren't limited to) sabotage events, Interconnection Reliability Operating Limit violations, voltage reductions, insufficient resources, arming of [special-protection system Remedial Action Schemes](#), etc.

R3.2. The agreed-upon actions from the associated Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan.

R4. Each of the Operating Procedures, Processes, and Plans addressed in Reliability Standard IRO-014 Requirement 1 and Requirement 3 shall:

R4.1. Include version control number or date.

R4.2. Include a distribution list.

R4.3. Be reviewed, at least once every three years, and updated if needed.

C. Measures

M1. The Reliability Coordinator's System Operators shall have available for Real-time use, the latest approved version of Operating Procedures, Processes, or Plans that require notifications, information exchange or the coordination of actions between Reliability Coordinators.

M1.1 These Operating Procedures, Processes, or Plans shall address:

M1.1.1 Communications and notifications, including the conditions under which one Reliability Coordinator notifies other Reliability Coordinators; the process to follow in making those notifications; and the data and information to be exchanged with other Reliability Coordinators.

M2.1.1 Energy and capacity shortages.

M3.1.1 Planned or unplanned outage information.

M4.1.1 Voltage control, including the coordination of reactive resources for voltage control.

M5.1.1 Coordination of information exchange to support reliability assessments.

M6.1.1 Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

M2. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were:

M2.1 Agreed to by all the Reliability Coordinators required to take the indicated action(s).

M2.2 Distributed to all Reliability Coordinators that are required to take the indicated action(s).

M3. The Reliability Coordinator's Operating Procedures, Processes, or Plans developed (for its System Operators' internal use) to support a Reliability Coordinator-to-Reliability Coordinator Operating Procedure, Process, or Plan received from another Reliability Coordinator shall:

M3.1 Be available to the Reliability Coordinator's System Operators for Real-time use,

M3.2 Include a reference to the associated source document, and

M3.3 Support the agreed-upon actions from the source document.

M4. The Reliability Coordinator's Operating Procedures, Processes, or Plans that addresses Reliability Coordinator-to-Reliability Coordinator coordination shall each include a version control number or date and a distribution list. The Reliability Coordinator shall have evidence that these Operating Procedures, Processes, or Plans were reviewed within the last three years.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

The Performance-Reset Period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep documentation for the prior calendar year and the current calendar year. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall also use a scheduled on-site review at least once every three years and investigations upon complaint. The Compliance Monitor shall conduct an investigation upon a complaint within 30 days of the alleged infraction's discovery date. The Compliance Monitor shall complete the investigation within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators to identify Operating Procedures, Processes or Plans that were distributed to the Reliability Coordinator being audited to verify that these documents are available for Real-time use by the receiving Reliability Coordinator's System Operators.

The Reliability Coordinator shall have the following documents available for inspection during an on-site audit or within five business days of a request as part of an investigation upon a complaint:

1.4.1 The latest version of its Operating Procedures, Processes, or Plans that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability.

1.4.2 Evidence of distribution of Operating Procedures, Processes, or Plans.

2. Levels of Non-Compliance

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions is present:

2.1.1 The latest versions of Operating Procedures, Processes, or Plans (identified through self-certification) that require notification, exchange of information, or coordination of actions with one or more other Reliability Coordinators to support Interconnection reliability do not include a version control number or date, and a distribution list.

2.1.2 The latest versions of Reliability Coordinator internal documents developed to support action(s) required as a result of other Reliability Coordinators do not include both a reference to the source Operating Procedure, Process, or Plan and the agreed-upon actions from the source Operating Procedure, Process, or Plan.

2.2. Level 2: There shall be a level two non-compliance if any of the following conditions is present:

2.2.1 Documents required by this standard were not distributed to all entities on the distribution list.

2.2.2 Documents required by this standard were not available for System Operators' Real-time use.

2.2.3 Documents required by this standard do not address all required topics.

2.3. Level 3: Documents required by this standard do not address any of the six required topics in Reliability Standard IRO-014-1(X) R1.

2.4. Level 4: Not Applicable.

E. Regional Differences

None Identified.

Version History

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Version 1	08/10/05	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” when used as adjective. 3. Changed standard header to be consistent with standard “Title.” 4. Initial capped heading “Definitions of Terms Used in Standard.” 5. Added “periods” to items where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, self-certification. 8. Changed apostrophes to “smart” symbols. 9. Added comma in all word strings “Procedures, Processes, or Plans,” etc. 10. Added hyphens to “Reliability Coordinator-to-Reliability Coordinator” where used as adjective. 11. Removed comma in item 2.1.2. 12. Removed extra spaces between words where appropriate. 	01/20/06
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-1a(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
 - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
 - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
 - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
 - R1.1.1. Includes at least:
 - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
 - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
 - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)
 - R1.1.2. Models all system Elements as in-service for the assumed initial conditions.
 - R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
 - R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.

- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS_F is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the

effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

Postbacks_F are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_F are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NF} are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NF} are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
 - M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
 - M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
 - M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a Remedial Action Scheme where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
 - M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1(X) and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the

- originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)
- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)

- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	<p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>	<p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>	<p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>	<p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>
R2	<p>One or both of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. The Transmission Operator does not include one required item in the study report required in R2.8. 	<p>One or both of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. The Transmission Operator does not include two required items in the study report required in R2.8. 	<p>One or both of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. The Transmission Operator does not include three required items in the study report required in R2.8. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. The Transmission Operator did not apply R2.7. The Transmission Operator does not include four or more required items in the study report required in R2.8

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by NERC Board of Trustees	
1a	Board approved 11/05/2009	Interpretation of R5 and R6	Interpretation (Project 2009-15)
1a	February 28, 2014	Updated VSLs based on June 24, 2013 approval.	
1a(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Appendix 1

Requirement Number and Text of Requirement
<p>MOD-001-01 Requirement R2:</p> <p>R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> R2.1. Hourly values for at least the next 48 hours. R2.2. Daily values for at least the next 31 calendar days. R2.3. Monthly values for at least the next 12 months (months 2-13). <p>MOD-001-01 Requirement R8:</p> <p>R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. R8.2. Daily values, once per day. R8.3. Monthly values, once per week.
Question #1
<p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>
Response to Question #1
<p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

Requirement Number and Text of Requirement

MOD-029-01(X) Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS_F is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

Question #2

Could OS_F in MOD-029-1(X) Requirement R5 and OS_{NF} in MOD-029-1(X) Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

Response to Question #2

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

A. Introduction

1. **Title:** Rated System Path Methodology
2. **Number:** MOD-029-1a(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.
4. **Applicability:**
 - 4.1. Each Transmission Operator that uses the Rated System Path Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
 - 4.2. Each Transmission Service Provider that uses the Rated System Path Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

- R1. When calculating TTCs for ATC Paths, the Transmission Operator shall use a Transmission model which satisfies the following requirements: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
 - R1.1. The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
 - R1.1.1. Includes at least:
 - R1.1.1.1. The Transmission Operator area. Equivalent representation of radial lines and facilities 161kV or below is allowed.
 - R1.1.1.2. All Transmission Operator areas contiguous with its own Transmission Operator area. (Equivalent representation is allowed.)
 - R1.1.1.3. Any other Transmission Operator area linked to the Transmission Operator's area by joint operating agreement. (Equivalent representation is allowed.)
 - R1.1.2. Models all system Elements as in-service for the assumed initial conditions.
 - R1.1.3. Models all generation (may be either a single generator or multiple generators) that is greater than 20 MVA at the point of interconnection in the studied area.
 - R1.1.4. Models phase shifters in non-regulating mode, unless otherwise specified in the Available Transfer Capability Implementation Document (ATCID).

- R1.1.5. Uses Load forecast by Balancing Authority.
 - R1.1.6. Uses Transmission Facility additions and retirements.
 - R1.1.7. Uses Generation Facility additions and retirements.
 - R1.1.8. Uses [Special Protection System \(SPS\) Remedial Action Scheme \(RAS\)](#) models where currently existing or projected for implementation within the studied time horizon.
 - R1.1.9. Models series compensation for each line at the expected operating level unless specified otherwise in the ATCID.
 - R1.1.10. Includes any other modeling requirements or criteria specified in the ATCID.
- R1.2. Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R2. The Transmission Operator shall use the following process to determine TTC:
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
 - R2.1. Except where otherwise specified within MOD-029-1(X), adjust base case generation and Load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the ATC Path while at the same time satisfying all planning criteria contingencies as follows:
 - R2.1.1. When modeling normal conditions, all Transmission Elements will be modeled at or below 100% of their continuous rating.
 - R2.1.2. When modeling contingencies the system shall demonstrate transient, dynamic and voltage stability, with no Transmission Element modeled above its Emergency Rating.
 - R2.1.3. Uncontrolled separation shall not occur.
 - R2.2. Where it is impossible to actually simulate a reliability-limited flow in a direction counter to prevailing flows (on an alternating current Transmission line), set the TTC for the non-prevailing direction equal to the TTC in the prevailing direction. If the TTC in the prevailing flow direction is dependent on a [Special Protection System \(SPS\) Remedial Action Scheme \(RAS\)](#), set the TTC for the non-prevailing flow direction equal to the greater of the maximum flow that can be simulated in the non-prevailing flow direction or the maximum TTC that can be achieved in the prevailing flow direction without use of a [RASSPS](#).
 - R2.3. For an ATC Path whose capacity is limited by contract, set TTC on the ATC Path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R2.1.
 - R2.4. For an ATC Path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram describing the interaction of the paths and the resulting TTC under specified conditions.

- R2.5.** The Transmission Operator shall identify when the TTC for the ATC Path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R2.1. The Transmission Operator shall include the resolution of this adverse impact in its study report for the ATC Path.
- R2.6.** Where multiple ownership of Transmission rights exists on an ATC Path, allocate TTC of that ATC Path in accordance with the contractual agreement made by the multiple owners of that ATC Path.
- R2.7.** For ATC Paths whose path rating, adjusted for seasonal variance, was established, known and used in operation since January 1, 1994, and no action has been taken to have the path rated using a different method, set the TTC at that previously established amount.
- R2.8.** Create a study report that describes the steps above that were undertaken (R2.1 – R2.7), including the contingencies and assumptions used, when determining the TTC and the results of the study. Where three phase fault damping is used to determine stability limits, that report shall also identify the percent used and include justification for use unless specified otherwise in the ATCID.
- R3.** Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R4.** Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- R5.** When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS_F is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

- R6.** When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

- R7.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postback_{SF} + counterflows_{SF}$$

Where

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

Postbacks_F are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_F are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

- R8.** When calculating non-firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NF} are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NF} are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

C. Measures

- M1.** Each Transmission Operator that uses the Rated System Path Methodology shall produce any Transmission model it used to calculate TTC for purposes of calculating ATC for each ATC Path, as required in R1, for the time horizon(s) to be examined. (R1)
- M1.1.** Production shall be in the same form and format used by the Transmission Operator to calculate the TTC, as required in R1. (R1)
- M1.2.** The Transmission model produced must include the areas listed in R1.1.1 (or an equivalent representation, as described in the requirement) (R1.1)
- M1.3.** The Transmission model produced must show the use of the modeling parameters stated in R1.1.2 through R1.1.10; except that, no evidence shall be required to prove: 1) utilization of a [Special Protection System Remedial Action Scheme](#) where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R1.1.2 through R1.1.10)
- M1.4.** The Transmission Operator must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R1.2)
- M2.** Each Transmission Operator that uses the Rated System Path Methodology shall produce the ATCID it uses to show where it has described and used additional modeling criteria in its ACTID that are not otherwise included in MOD-29 (R1.1.4, R.1.1.9, and R1.1.10).
- M3.** Each Transmission Operator that uses the Rated System Path Methodology with paths with ratings established prior to January 1, 1994 shall provide evidence the path and its rating were established prior to January 1, 1994. (R2.7)
- M4.** Each Transmission Operator that uses the Rated System Path Methodology shall produce as evidence the study reports, as required in R.2.8, for each path for which it determined TTC for the period examined. (R2)
- M5.** Each Transmission Operator shall provide evidence that it used the lesser of the calculated TTC or the SOL as the TTC, by producing: 1) all values calculated pursuant to R2 for each ATC Path, 2) Any corresponding SOLs for those ATC Paths, and 3) the TTC set by the Transmission Operator and given to the Transmission Service Provider for use in R7 and R8 for each ATC Path. (R3)
- M6.** Each Transmission Operator shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R4)
- M7.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R5 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-029-1(X) and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any

recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R5 to calculate its firm ETC. (R5)

- M8.** The Transmission Service Provider shall demonstrate compliance with R5 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R6 and with data used to calculate this specified value for the designated time period. The data used must meet the requirements specified in the MOD-029 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R6 to calculate its non-firm ETC. (R6)
- M9.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R7. Such documentation must show that only the variables allowed in R7 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R7)
- M10.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

- The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall have its latest models used to determine TTC for R1. (M1)
- The Transmission Operator shall have the current, in force ATCID(s) provided by its Transmission Service Provider(s) and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1. (M2)
- The Transmission Operator shall retain evidence of any path and its rating that was established prior to January 1, 1994. (M3)
- The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R2. (M4)
- The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R3 and R4. (M5 and M6)
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R5 and R6 for the most recent 14 days; evidence to show compliance in calculating daily values required in R5 and R6 for the most recent 30 days; and evidence to show compliance in calculating daily values required in R5 and R6 for the most recent sixty days. (M7 and M8)
- The Transmission Service Provider shall retain evidence for the most recent three calendar years plus the current year to show compliance with R7 and R8. (M9 and M10)
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	<p>The Transmission Operator used a model that met all but one of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized one to ten Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>	<p>The Transmission Operator used a model that met all but two of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized eleven to twenty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>	<p>The Transmission Operator used a model that met all but three of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized twenty-one to thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>	<p>The Transmission Operator used a model that did not meet four or more of the modeling requirements specified in R1.1.</p> <p style="text-align: center;">OR</p> <p>The Transmission Operator utilized more than thirty Facility Ratings that were different from those specified by a Transmission Owner or Generation Owner in their Transmission model. (R1.2)</p>
R2	<p>One or both of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using one of the items in sub-requirements R2.1-R2.6. The Transmission Operator does not include one required item in the study report required in R2.8. 	<p>One or both of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using two of the items in sub-requirements R2.1-R2.6. The Transmission Operator does not include two required items in the study report required in R2.8. 	<p>One or both of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using three of the items in sub-requirements R2.1-R2.6. The Transmission Operator does not include three required items in the study report required in R2.8. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not calculate TTC using four or more of the items in sub-requirements R2.1-R2.6. The Transmission Operator did not apply R2.7. The Transmission Operator does not include four or more required items in the study report required in R2.8

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than zero ATC Paths, BUT, not more than 1% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 1% of all ATC Paths or 1 ATC Path (whichever is greater), BUT not more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL for more than 2% of all ATC Paths or 2 ATC Paths (whichever is greater), BUT not more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Operator did not specify the TTC as the lesser of the TTC calculated using the process described in R2 or any associated SOL, for more than 5% of all ATC Paths or 3 ATC Paths (whichever is greater).
R4.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than seven, but not more than 14 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 14, but not more than 21 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 21, but not more than 28 calendar days after the report was finalized.	The Transmission Operator provided the TTC and study report to the Transmission Service Provider more than 28 calendar days after the report was finalized.
R5.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M7 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

Standard MOD-029-1a(X)— Rated System Path Methodology

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M8 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R7.	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R7 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	8/26/2008	Adopted by NERC Board of Trustees	
1a	Board approved 11/05/2009	Interpretation of R5 and R6	Interpretation (Project 2009-15)
1a	February 28, 2014	Updated VSLs based on June 24, 2013 approval.	
1a	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Appendix 1

Requirement Number and Text of Requirement
<p>MOD-001-01 Requirement R2:</p> <p>R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):</p> <ul style="list-style-type: none"> R2.1. Hourly values for at least the next 48 hours. R2.2. Daily values for at least the next 31 calendar days. R2.3. Monthly values for at least the next 12 months (months 2-13). <p>MOD-001-01 Requirement R8:</p> <p>R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:</p> <ul style="list-style-type: none"> R8.1. Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation. R8.2. Daily values, once per day. R8.3. Monthly values, once per week.
Question #1
<p>Is the “advisory ATC” used under the NYISO tariff subject to the ATC calculation and recalculation requirements in MOD-001-1 Requirements R2 and R8? If not, is it necessary to document the frequency of “advisory” calculations in the responsible entity’s Available Transfer Capability Implementation Document?</p>
Response to Question #1
<p>Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific “ATC Paths.” The NERC definition of ATC Path is “Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path.” Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO’s “advisory ATC” is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths.</p>

The second part of NYISO’s question is only applicable if the first part was answered in the negative and therefore will not be addressed.

Requirement Number and Text of Requirement

MOD-029-01(X) Requirements R5 and R6:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NITS_F is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_F is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider’s Open Access Transmission Tariff or “safe harbor tariff.”

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETC_{NF}) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

NITS_{NF} is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

Question #2

Could OS_F in MOD-029-1(X) Requirement R5 and OS_{NF} in MOD-029-1(X) Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

Response to Question #2

This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.

A. Introduction

1. **Title:** Flowgate Methodology
2. **Number:** MOD-030-02(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
 - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
 - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
 - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
 - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
 - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
 - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
 - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
 - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
 - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
 - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
 - R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of Remedial Action Schemes.

R2.1.1.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.1.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.2. Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.

R2.1.2.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of Remedial Action Schemes.

R2.1.2.2. Only the most limiting element in a series configuration needs to be included as a Flowgate.

R2.1.2.3. If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.

R2.1.3. Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.

R2.1.4. Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:

R2.1.4.1. The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and

- Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
- A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

R2.2. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.

R2.3. At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.

R2.4. Establish the TFC of each of the defined Flowgates as equal to:

- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
- For voltage or stability limits, the flow that will respect the SOL of the Flowgate.

R2.5. At a minimum, establish the TFC once per calendar year.

R2.5.1. If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.

R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R3.1. Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.

R3.2. Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.

R3.3. Updated at least once per month for AFC calculations for months two through 13.

R3.4. Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.

R3.5. Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

R4. When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
- If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load

- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
 - R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage¹ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
 - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
 - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
 - R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
 - R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage² used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
 - R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
 - R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage³ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
 - R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC_{NFi}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

¹ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

² A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

³ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage⁴ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage⁵ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider’s area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage⁶ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{SFi} + counterflows_{SFi}$$

Where:

AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.

⁴ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

⁵ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

⁶ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.

Postbacks_{Fi} are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{Fi} are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NF} are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NF} are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

Where:

ATC is the Available Transfer Capability.

P is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage⁷ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

PATC_n is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

AFC_n is the Available Flowgate Capability of a Flowgate *n*.

DF_{np} is the distribution factor for Flowgate *n* relative to path *p*.

C. Measures

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

⁷ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID the information described in R1.1. OR The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).	The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).
R2.	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2. The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3. The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not 	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1. The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2. The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3. 	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1. The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2. The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3. 	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1. The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2. The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. 	<ul style="list-style-type: none"> The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update. The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1) The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. 	<p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1) The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. 	<p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3. The Transmission Operator did not determine the TFC for a flowgate as described in R2.4. The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5) The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1) The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not update the model per R3.2 for more than 4 calendar days The Transmission Operator did not update the model for per R3.3 for more than ten weeks The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area. The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.
R4.	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..	10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..	15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..	more than 3 reservations, whichever is greater..
R5.	The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	One or more of the following: <ul style="list-style-type: none"> • The Transmission Service Provider did not use the model provided by the Transmission Operator. • The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. • The Transmission Service provider did not use AFC provided by a third party.
R6.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calculated in the measure or 25MW, whichever is greater..	calculated in the measure or 35MW, whichever is greater.	calculated in the measure or 45MW, whichever is greater.	
R7.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).
R9.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Flowgates or 1 Flowgate (whichever is greater).	or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	Flowgates or more than 3 Flowgates (whichever is greater).
R10	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	N/A	The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11.

A. Regional Differences

None identified.

B. Associated Documents

Version History

Version	Date	Action	Change Tracking
2		Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11 Made conforming changes to M18 and VSLs for R2 and R11	Revised
2(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Flowgate Methodology
2. **Number:** MOD-030-02(X)
3. **Purpose:** To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Flowgate Methodology to support analysis and system operations.
4. **Applicability:**
 - 4.1.1 Each Transmission Operator that uses the Flowgate Methodology to support the calculation of Available Flowgate Capabilities (AFCs) on Flowgates.
 - 4.1.2 Each Transmission Service Provider that uses the Flowgate Methodology to calculate AFCs on Flowgates.
5. **Proposed Effective Date:** The date upon which MOD-030-01 is currently scheduled to become effective.

B. Requirements

- R1. The Transmission Service Provider shall include in its “Available Transfer Capability Implementation Document” (ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
 - R1.1. The criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates that are to be considered in Available Flowgate Capability (AFC) calculations.
 - R1.2. The following information on how source and sink for transmission service is accounted for in AFC calculations including:
 - R1.2.1. Define if the source used for AFC calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation.
 - R1.2.2. Define if the sink used for AFC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation.
 - R1.2.3. The source/sink or POR/POD identification and mapping to the model.
 - R1.2.4. If the Transmission Service Provider’s AFC calculation process involves a grouping of generators, the ATCID must identify how these generators participate in the group.
- R2. The Transmission Operator shall perform the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
 - R2.1. Include Flowgates used in the AFC process based, at a minimum, on the following criteria:
 - R2.1.1. Results of a first Contingency transfer analysis for ATC Paths internal to a Transmission Operator’s system up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an OTDF of at least 5% and within the Transmission Operator’s system are included as Flowgates.
 - R2.1.1.1. Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the

applicable time periods, including use of [Special Protection System Remedial Action Schemes](#).

- R2.1.1.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.
- R2.1.1.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.
- R2.1.2.** Results of a first Contingency transfer analysis from all adjacent Balancing Authority source and sink (as defined in the ATCID) combinations up to the path capability such that at a minimum the first three limiting Elements and their worst associated Contingency combinations with an Outage Transfer Distribution Factor (OTDF) of at least 5% and within the Transmission Operator's system are included as Flowgates unless the interface between such adjacent Balancing Authorities is accounted for using another ATC methodology.
 - R2.1.2.1.** Use first Contingency criteria consistent with those first Contingency criteria used in planning of operations for the applicable time periods, including use of [Special Protection System Remedial Action Schemes](#).
 - R2.1.2.2.** Only the most limiting element in a series configuration needs to be included as a Flowgate.
 - R2.1.2.3.** If any limiting element is kept within its limit for its associated worst Contingency by operating within the limits of another Flowgate, then no new Flowgate needs to be established for such limiting elements or Contingencies.
- R2.1.3.** Any limiting Element/Contingency combination at least within its Reliability Coordinator's Area that has been subjected to an Interconnection-wide congestion management procedure within the last 12 months, unless the limiting Element/Contingency combination is accounted for using another ATC methodology or was created to address temporary operating conditions.
- R2.1.4.** Any limiting Element/Contingency combination within the Transmission model that has been requested to be included by any other Transmission Service Provider using the Flowgate Methodology or Area Interchange Methodology, where:
 - R2.1.4.1.** The coordination of the limiting Element/Contingency combination is not already addressed through a different methodology, and
 - Any generator within the Transmission Service Provider's area has at least a 5% Power Transfer Distribution Factor (PTDF) or Outage Transfer Distribution Factor (OTDF) impact on the Flowgate when delivered to the aggregate load of its own area, or
 - A transfer from any Balancing Area within the Transmission Service Provider's area to a Balancing Area

adjacent has at least a 5% PTDF or OTDF impact on the Flowgate.

- The Transmission Operator may utilize distribution factors less than 5% if desired.

R2.1.4.2. The limiting Element/Contingency combination is included in the requesting Transmission Service Provider's methodology.

- R2.2.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgate definitions at least once per calendar year.
- R2.3.** At a minimum, establish a list of Flowgates by creating, modifying, or deleting Flowgates that have been requested as part of R2.1.4 within thirty calendar days from the request.
- R2.4.** Establish the TFC of each of the defined Flowgates as equal to:
- For thermal limits, the System Operating Limit (SOL) of the Flowgate.
 - For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
- R2.5.** At a minimum, establish the TFC once per calendar year.
- R2.5.1.** If notified of a change in the Rating by the Transmission Owner that would affect the TFC of a flowgate used in the AFC process, the TFC should be updated within seven calendar days of the notification.
- R2.6.** Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.

R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

- R3.1.** Contains generation Facility Ratings, such as generation maximum and minimum output levels, specified by the Generator Owners of the Facilities within the model.
- R3.2.** Updated at least once per day for AFC calculations for intra-day, next day, and days two through 30.
- R3.3.** Updated at least once per month for AFC calculations for months two through 13.
- R3.4.** Contains modeling data and system topology for the Facilities within its Reliability Coordinator's Area. Equivalent representation of radial lines and Facilities 161kV or below is allowed.
- R3.5.** Contains modeling data and system topology (or equivalent representation) for immediately adjacent and beyond Reliability Coordination Areas.

- R4.** When calculating AFCs, the Transmission Service Provider shall represent the impact of Transmission Service as follows: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the source.
 - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the

Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the source.

- If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the source, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
- If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider's Transmission model, use the discretely modeled point as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an "equivalence" or "aggregate" representation in the Transmission Service Provider's Transmission model, use the modeled equivalence or aggregate as the sink.
- If the sink, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point or an "equivalence" representation in the Transmission Service Provider's Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.
- If the sink, as specified in the ATCID, has not been identified in the reservation use the immediately adjacent Balancing Authority associated with the Transmission Service Provider receiving the power as the sink.

R5. When calculating AFCs, the Transmission Service Provider shall: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R5.1. Use the models provided by the Transmission Operator.

R5.2. Include in the transmission model expected generation and Transmission outages, additions, and retirements within the scope of the model as specified in the ATCID and in effect during the applicable period of the AFC calculation for the Transmission Service Provider's area, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed.

R5.3. For external Flowgates, identified in R2.1.4, use the AFC provided by the Transmission Service Provider that calculates AFC for that Flowgate.

R6. When calculating the impact of ETC for firm commitments (ETC_{Fi}) for all time periods for a Flowgate, the Transmission Service Provider shall sum the following: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R6.1. The impact of firm Network Integration Transmission Service, including the impacts of generation to load, in the model referenced in R5.2 for the Transmission Service Provider's area, based on:

R6.1.1. Load forecast for the time period being calculated, including Native Load and Network Service load

- R6.1.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.2.** The impact of any firm Network Integration Transmission Service, including the impacts of generation to load in the model referenced in R5.2 and has a distribution factor equal to or greater than the percentage¹ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed based on:
 - R6.2.1.** Load forecast for the time period being calculated, including Native Load and Network Service load
 - R6.2.2.** Unit commitment and Dispatch Order, to include all designated network resources and other resources that are committed or have the legal obligation to run as specified in the Transmission Service Provider's ATCID.
- R6.3.** The impact of all confirmed firm Point-to-Point Transmission Service expected to be scheduled, including roll-over rights for Firm Transmission Service contracts, for the Transmission Service Provider's area.
- R6.4.** The impact of any confirmed firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, including roll-over rights for Firm Transmission Service contracts having a distribution factor equal to or greater than the percentage² used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.5.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider's area.
- R6.6.** The impact of any Grandfathered firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage³ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R6.7.** The impact of other firm services determined by the Transmission Service Provider.
- R7.** When calculating the impact of ETC for non-firm commitments (ETC_{NFi}) for all time periods for a Flowgate the Transmission Service Provider shall sum: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

¹ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

² A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

³ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- R7.1.** The impact of all confirmed non-firm Point-to-Point Transmission Service expected to be scheduled for the Transmission Service Provider’s area.
- R7.2.** The impact of any confirmed non-firm Point-to-Point Transmission Service expected to be scheduled, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, that have a distribution factor equal to or greater than the percentage⁴ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.3.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow for the Transmission Service Provider’s area.
- R7.4.** The impact of any Grandfathered non-firm obligations expected to be scheduled or expected to flow that have a distribution factor equal to or greater than the percentage⁵ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.5.** The impact of non-firm Network Integration Transmission Service serving Load within the Transmission Service Provider’s area (i.e., secondary service), to include load growth, and losses not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.
- R7.6.** The impact of any non-firm Network Integration Transmission Service (secondary service) with a distribution factor equal to or greater than the percentage⁶ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider, filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers, for all adjacent Transmission Service Providers and any other Transmission Service Providers with which coordination agreements have been executed.
- R7.7.** The impact of other non-firm services determined by the Transmission Service Provider.
- R8.** When calculating firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{SFi} + counterflows_{SFi}$$

Where:

AFC_F is the firm Available Flowgate Capability for the Flowgate for that period.

⁴ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

⁵ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

⁶ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

CBM_i is the impact of the Capacity Benefit Margin on the Flowgate during that period.

TRM_i is the impact of the Transmission Reliability Margin on the Flowgate during that period.

Postbacks_{Fi} are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{Fi} are adjustments to firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R9.** When calculating non-firm AFC for a Flowgate for a specified period, the Transmission Service Provider shall use the following algorithm (subject to allocation processes described in the ATCID): [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBM_{Si} - TRM_{Ui} + Postbacks_{NFi} + counterflows$$

Where:

AFC_{NF} is the non-firm Available Flowgate Capability for the Flowgate for that period.

TFC is the Total Flowgate Capability of the Flowgate.

ETC_{Fi} is the sum of the impacts of existing firm Transmission commitments for the Flowgate during that period.

ETC_{NFi} is the sum of the impacts of existing non-firm Transmission commitments for the Flowgate during that period.

CBM_{Si} is the impact of any schedules during that period using Capacity Benefit Margin.

TRM_{Ui} is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NF} are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NF} are adjustments to non-firm AFC as determined by the Transmission Service Provider and specified in their ATCID.

- R10.** Each Transmission Service Provider shall recalculate AFC, utilizing the updated models described in R3.2, R3.3, and R5, at a minimum on the following frequency, unless none of the calculated values identified in the AFC equation have changed: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

R10.1. For hourly AFC, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the AFC equation.

R10.2. For daily AFC, once per day.

R10.3. For monthly AFC, once per week.

- R11.** When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Service Provider shall convert those values based on the following algorithm: [*Violation Risk Factor: To Be Determined*] [*Time Horizon: Operations Planning*]

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \dots, PATC_n\}$$

$$PATC_n = \frac{AFC_n}{DF_{np}}$$

Where:

ATC is the Available Transfer Capability.

P is the set of partial Available Transfer Capabilities for all “impacted” Flowgates honored by the Transmission Service Provider; a Flowgate is considered “impacted” by a path if the Distribution Factor for that path is greater than the percentage⁷ used to curtail in the Interconnection-wide congestion management procedure used by the Transmission Service Provider on an OTDF Flowgate or PTDF Flowgate.

PATC_n is the partial Available Transfer Capability for a path relative to a Flowgate *n*.

AFC_n is the Available Flowgate Capability of a Flowgate *n*.

DF_{np} is the distribution factor for Flowgate *n* relative to path *p*.

C. Measures

- M1.** Each Transmission Service Provider shall provide its ATCID and other evidence (such as written documentation) to show that its ATCID contains the criteria used by the Transmission Operator to identify sets of Transmission Facilities as Flowgates and information on how sources and sinks are accounted for in AFC calculations. (R1)
- M2.** The Transmission Operator shall provide evidence (such as studies and working papers) that all Flowgates that meet the criteria described in R2.1 are considered in its AFC calculations. (R2.1)
- M3.** The Transmission Operator shall provide evidence (such as logs) that it updated its list of Flowgates at least once per calendar year. (R2.2)
- M4.** The Transmission Operator shall provide evidence (such as logs and dated requests) that it updated the list of Flowgates within thirty calendar days from a request. (R2.3)
- M5.** The Transmission Operator shall provide evidence (such as data or models) that it determined the TFC for each Flowgate as defined in R2.4. (R2.4)
- M6.** The Transmission Operator shall provide evidence (such as logs) that it established the TFCs for each Flowgate in accordance with the timing defined in R2.5. (R2.5)
- M7.** The Transmission Operator shall provide evidence (such as logs and electronic communication) that it provided the Transmission Service Provider with updated TFCs within seven calendar days of their determination. (R2.6)

⁷ A percentage less than that used in the Interconnection-wide congestion management procedure may be utilized.

- M8.** The Transmission Operator shall provide evidence (such as written documentation, logs, models, and data) that the Transmission model used to determine AFCs contains the information specified in R3. (R3)
- M9.** The Transmission Service Provider shall provide evidence (such as written documentation and data) that the modeling of point-to-point reservations was based on the rules described in R4. (R4)
- M10.** The Transmission Service Provider shall provide evidence including the models received from Transmission Operators and other evidence (such as documentation and data) to show that it used the Transmission Operator's models in calculating AFC. (R5.1)
- M11.** The Transmission Service Provider shall provide evidence (such as written documentation, electronic communications, and data) that all expected generation and Transmission outages, additions, and retirements were included in the AFC calculation as specified in the ATCID. (R5.2)
- M12.** The Transmission Service Provider shall provide evidence (such as logs, electronic communications, and data) that AFCs provided by third parties on external Flowgates were used instead of those calculated by the Transmission Operator. (R5.3)
- M13.** The Transmission Service Provider shall demonstrate compliance with R6 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R6 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in this standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements defined in R6 to calculate its firm ETC. (R6)
- M14.** The Transmission Service Provider shall demonstrate compliance with R7 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the requirements defined in R7 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in the standard and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the requirements in R7 to calculate its non-firm ETC. (R7)
- M15.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm AFCs, as required in R8. Such documentation must show that only the variables allowed in R8 were used to calculate firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R8)
- M16.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm AFCs, as required in R9. Such documentation must show that only the variables allowed in R9 were used to calculate non-firm AFCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the

value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R9)

M17. The Transmission Service Provider shall provide evidence (such as documentation, dated logs, and data) that it calculated AFC on the frequency defined in R10. (R10)

M18. The Transmission Service Provider shall provide evidence (such as documentation and data) when converting Flowgate AFCs to ATCs for ATC Paths, it follows the procedure described in R11. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Time Frame

Not applicable.

1.3. Data Retention

The Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to determine flowgates and TFC and evidence of the previous version to show compliance with R2 and R3.
- The Transmission Operator shall retain evidence to show compliance with R2.1, R2.3 for the most recent 12 months.
- The Transmission Operator shall retain evidence to show compliance with R2.2, R2.4 and R2.5 for the most recent three calendar years plus current year.
- The Transmission Service Provider shall retain evidence to show compliance with R4 for 12 months or until the model used to calculate AFC is updated, whichever is longer.
- The Transmission Service Provider shall retain evidence to show compliance with R5, R8, R9, R10, and R11 for the most recent calendar year plus current year.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R6 and R7 for the most recent 14 days; evidence to show compliance in calculating daily values required in R6 and R7 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R6 and R7 for the most recent sixty days.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Transmission Service Provider does not include in its ATCID one or two of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID three of the sub-requirements listed under R1.2, or the sub-requirement is incomplete.	The Transmission Service Provider does not include in its ATCID the information described in R1.1. OR The Transmission Service Provider does not include in its ATCID the information described in R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).	The Transmission Service Provider does not include in its ATCID the information described in R1.1 and R1.2 (1.2.1, 1.2.2., 1.2.3, and 1.2.4 are missing).
R2.	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator established its list of Flowgates less frequently than once per calendar year, but not more than three months late as described in R2.2. The Transmission Operator established its list of Flowgates more than thirty days, but not more than sixty days, following a request to create, modify or delete a flowgate as described in R2.3. The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 7 days, but it has not 	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator did not include a Flowgate in their AFC calculations that met the criteria described in R2.1. The Transmission Operator established its list of Flowgates more than three months late, but not more than six months late as described in R2.2. The Transmission Operator established its list of Flowgates more than sixty days, but not more than ninety days, following a request to create, modify or delete a flowgate as described in R2.3. 	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator did not include two to five Flowgates in their AFC calculations that met the criteria described in R2.1. The Transmission Operator established its list of Flowgates more than six months late, but not more than nine months late as described in R2.2. The Transmission Operator established its list of Flowgates more than ninety days, but not more than 120 days, following a request to create, modify or delete a flowgate as described in R2.3. 	One or more of the following: <ul style="list-style-type: none"> The Transmission Operator did not include six or more Flowgates in their AFC calculations that met the criteria described in R2.1. The Transmission Operator established its list of Flowgates more than nine months late as described in R2.2. The Transmission Operator did not establish its list of internal Flowgates as described in R2.2. The Transmission Operator established its list of Flowgates more than 120 days following a request to create, modify or delete a

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>been more than 14 days since the notification (R2.5.1)</p> <ul style="list-style-type: none"> The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs within seven days (one week) of their determination, but is has not been more than 14 days (two weeks) since their determination. 	<ul style="list-style-type: none"> The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been not more than 15 months since the last update. The Transmission Operator has not updated its Flowgate TFC when notified by the Transmission Owner in more than 14 days, but it has not been more than 21 days since the notification (R2.5.1) The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 14 days (two weeks) of their determination, but is has not been more than 21 days (three weeks) since their determination. 	<p>The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 15 months but not more than 18 months since the last update.</p> <ul style="list-style-type: none"> The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 21 days, but it has not been more than 28 days since the notification (R2.5.1) The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 21 days (three weeks) of their determination, but is has not been more than 28 days (four weeks) since their determination. 	<p>flowgate as described in R2.3.</p> <ul style="list-style-type: none"> The Transmission Operator did not establish its list of external Flowgates following a request to create, modify or delete an external flowgate as described in R2.3. The Transmission Operator did not determine the TFC for a flowgate as described in R2.4. The Transmission Operator has not updated its Flowgate TFCs at least once within a calendar year, and it has been more than 18 months since the last update. (R2.5) The Transmission Operator has not updated its Flowgate TFCs when notified by the Transmission Owner in more than 28 calendar days (R2.5.1) The Transmission Operator has not provided its Transmission Service Provider with its Flowgate TFCs in more than 28 days (4 weeks) of their determination.

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	<p>One or more of the following:</p> <ul style="list-style-type: none"> • The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for one or more calendar days but not more than 2 calendar days • The Transmission Operator did not update the model for per R3.3 for one or more months but not more than six weeks 	<p>One or more of the following:</p> <ul style="list-style-type: none"> • The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 2 calendar days but not more than 3 calendar days • The Transmission Operator did not update the model for per R3.3 for more than six weeks but not more than eight weeks 	<p>One or more of the following:</p> <ul style="list-style-type: none"> • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not update the model per R3.2 for more than 3 calendar days but not more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than eight weeks but not more than ten weeks 	<p>One or more of the following:</p> <ul style="list-style-type: none"> • The Transmission Operator did not update the model per R3.2 for more than 4 calendar days • The Transmission Operator did not update the model for per R3.3 for more than ten weeks • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission operator did not include in the Transmission model detailed modeling data and topology for its own Reliability Coordinator area. • The Transmission operator did not include in the Transmission modeling data and topology for immediately adjacent and beyond Reliability Coordinator area.
R4.	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than zero, but not more than</p>	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 5%, but not more than</p>	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 10%, but not more than</p>	<p>The Transmission Service Provider did not represent the impact of Transmission Service as described in R4 for more than 15% of all reservations; or</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	5% of all reservations; or more than zero, but not more than 1 reservation, whichever is greater..	10% of all reservations; or more than 1, but not more than 2 reservations, whichever is greater..	15% of all reservations; or more than 2, but not more than 3 reservations, whichever is greater..	more than 3 reservations, whichever is greater..
R5.	The Transmission Service Provider did not include in the AFC process one to ten expected generation or Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process eleven to twenty-five expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	The Transmission Service Provider did not include in the AFC process twenty-six to fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID.	One or more of the following: <ul style="list-style-type: none"> • The Transmission Service Provider did not use the model provided by the Transmission Operator. • The Transmission Service Provider did not include in the AFC process more than fifty expected generation and Transmission outages, additions or retirements within the scope of the model as specified in the ATCID. • The Transmission Service provider did not use AFC provided by a third party.
R6.	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value	For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M13 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.

Standard MOD-030-02(X) — Flowgate Methodology

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	calculated in the measure or 25MW, whichever is greater..	calculated in the measure or 35MW, whichever is greater.	calculated in the measure or 45MW, whichever is greater.	
R7.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.	For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M14 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.
R8.	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all Flowgates or 1 Flowgate (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 5% of all Flowgates or 1 Flowgates (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 10% of all Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R8 when determining firm AFC, or used additional elements, for more than 15% of all Flowgates or more than 3 Flowgates (whichever is greater).
R9.	The Transmission Service Provider did not use all the elements defined in R8 when determining non-firm AFC, or used additional elements, for more than zero Flowgates, but not more than 5% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 5% of all Flowgates	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 10% of all	The Transmission Service Provider did not use all the elements defined in R9 when determining non-firm AFC, or used additional elements, for more than 15% of all

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Flowgates or 1 Flowgate (whichever is greater).	or 1 Flowgate (whichever is greater), but not more than 10% of all Flowgates or 2 Flowgates (whichever is greater).	Flowgates or 2 Flowgates (whichever is greater), but not more than 15% of all Flowgates or 3 Flowgates (whichever is greater).	Flowgates or more than 3 Flowgates (whichever is greater).
R10	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more hours but not more than 15 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for one or more calendar days but not more than 3 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for seven or more calendar days, but less than 14 calendar days. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 15 hours but not more than 20 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 3 calendar days but not more than 4 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 14 or more calendar days, but less than 21 calendar days. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 20 hours but not more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 4 calendar days but not more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 21 or more calendar days, but less than 28 calendar days. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> ▪ For Hourly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 25 hours, and was in excess of the 175-hour per year requirement. ▪ For Daily, the values described in the AFC equation changed and the Transmission Service provider did not calculate for more than 5 calendar days. ▪ For Monthly, the values described in the AFC equation changed and the Transmission Service provider did not calculate for 28 or more calendar days.

Standard MOD-030-02(X) — Flowgate Methodology

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R11.	N/A	N/A	N/A	The Transmission Service Provider did not follow the procedure for converting Flowgate AFCs to ATCs described in R11.

A. Regional Differences

None identified.

B. Associated Documents

Version History

Version	Date	Action	Change Tracking
2		Modified R2.1.1.3, R2.1.2.3, R2.1.3, R2.2, R2.3 and R11 Made conforming changes to M18 and VSLs for R2 and R11	Revised
2 (X)	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

- 1. Title:** Nuclear Plant Interface Coordination
- 2. Number:** NUC-001-2.1(X)
- 3. Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
- 4. Applicability:**
 - 4.1.** Nuclear Plant Generator Operator.
 - 4.2.** Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
 - 4.2.1** Transmission Operators.
 - 4.2.2** Transmission Owners.
 - 4.2.3** Transmission Planners.
 - 4.2.4** Transmission Service Providers.
 - 4.2.5** Balancing Authorities.
 - 4.2.6** Reliability Coordinators.
 - 4.2.7** Planning Coordinators.
 - 4.2.8** Distribution Providers.
 - 4.2.9** Load-serving Entities.
 - 4.2.10** Generator Owners.
 - 4.2.11** Generator Operators.
- 5. Effective Date:** April 1, 2010

B. Requirements

- R1.** The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements¹ that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]
- R3.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
 - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
 - R4.2.** Operate the electric system to meet the NPIRs.
 - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
 - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
 - R9.2.** Technical requirements and analysis:
 - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
 - R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
 - R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
 - R9.3.** Operations and maintenance coordination:

- R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
- R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
- R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
- R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
- R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
- R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
- R9.3.7.** Coordination of the NPIRs with transmission system Remedial Action Schemes and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
 - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
 - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
 - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
 - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
 - R9.4.5.** Provisions for personnel training, as related to NPIRs.

C. Measures

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
 - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
 - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
 - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Enforcement Authority**

Regional Entity.
 - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
 - 1.3. Compliance Monitoring and Enforcement Processes:**
 - Compliance Audits
 - Self-Certifications
 - Spot Checking
 - Compliance Violation Investigations
 - Self-Reporting

Complaints

1.4. Data Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

E. Regional Differences

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

Nuclear Plant Licensing Requirements (NPLR) are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this

Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	May 2, 2007	Approved by Board of Trustees	New
2	To be determined	Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.	Revision
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	January 22, 2010	Approved by FERC on January 21, 2010 Added Effective Date	Update
2	February 7, 2013	R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2.1	April 11, 2012	Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
2.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
2.1	November 21, 2013	R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Nuclear Plant Interface Coordination
2. **Number:** NUC-001-2.1(X)
3. **Purpose:** This standard requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown.
4. **Applicability:**
 - 4.1. Nuclear Plant Generator Operator.
 - 4.2. Transmission Entities shall mean all entities that are responsible for providing services related to Nuclear Plant Interface Requirements (NPIRs). Such entities may include one or more of the following:
 - 4.2.1 Transmission Operators.
 - 4.2.2 Transmission Owners.
 - 4.2.3 Transmission Planners.
 - 4.2.4 Transmission Service Providers.
 - 4.2.5 Balancing Authorities.
 - 4.2.6 Reliability Coordinators.
 - 4.2.7 Planning Coordinators.
 - 4.2.8 Distribution Providers.
 - 4.2.9 Load-serving Entities.
 - 4.2.10 Generator Owners.
 - 4.2.11 Generator Operators.
5. **Effective Date:** April 1, 2010

B. Requirements

- R1. The Nuclear Plant Generator Operator shall provide the proposed NPIRs in writing to the applicable Transmission Entities and shall verify receipt [*Risk Factor: Lower*]
- R2. The Nuclear Plant Generator Operator and the applicable Transmission Entities shall have in effect one or more Agreements¹ that include mutually agreed to NPIRs and document how the Nuclear Plant Generator Operator and the applicable Transmission Entities shall address and implement these NPIRs. [*Risk Factor: Medium*]
- R3. Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall incorporate the NPIRs into their planning analyses of the electric system and shall communicate the results of these analyses to the Nuclear Plant Generator Operator. [*Risk Factor: Medium*]

1. Agreements may include mutually agreed upon procedures or protocols in effect between entities or between departments of a vertically integrated system.

- R4.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall: [*Risk Factor: High*]
 - R4.1.** Incorporate the NPIRs into their operating analyses of the electric system.
 - R4.2.** Operate the electric system to meet the NPIRs.
 - R4.3.** Inform the Nuclear Plant Generator Operator when the ability to assess the operation of the electric system affecting NPIRs is lost.
- R5.** The Nuclear Plant Generator Operator shall operate per the Agreements developed in accordance with this standard. [*Risk Factor: High*]
- R6.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities and the Nuclear Plant Generator Operator shall coordinate outages and maintenance activities which affect the NPIRs. [*Risk Factor: Medium*]
- R7.** Per the Agreements developed in accordance with this standard, the Nuclear Plant Generator Operator shall inform the applicable Transmission Entities of actual or proposed changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R8.** Per the Agreements developed in accordance with this standard, the applicable Transmission Entities shall inform the Nuclear Plant Generator Operator of actual or proposed changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that may impact the ability of the electric system to meet the NPIRs. [*Risk Factor: High*]
- R9.** The Nuclear Plant Generator Operator and the applicable Transmission Entities shall include, as a minimum, the following elements within the agreement(s) identified in R2: [*Risk Factor: Medium*]
 - R9.1.** Administrative elements: (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.1.** Definitions of key terms used in the agreement. (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.2.** Names of the responsible entities, organizational relationships, and responsibilities related to the NPIRs. (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.3.** A requirement to review the agreement(s) at least every three years. (Retirement approved by FERC effective January 21, 2014.)
 - R9.1.4.** A dispute resolution mechanism. (Retirement approved by FERC effective January 21, 2014.)
 - R9.2.** Technical requirements and analysis:
 - R9.2.1.** Identification of parameters, limits, configurations, and operating scenarios included in the NPIRs and, as applicable, procedures for providing any specific data not provided within the agreement.
 - R9.2.2.** Identification of facilities, components, and configuration restrictions that are essential for meeting the NPIRs.
 - R9.2.3.** Types of planning and operational analyses performed specifically to support the NPIRs, including the frequency of studies and types of Contingencies and scenarios required.
 - R9.3.** Operations and maintenance coordination:

- R9.3.1.** Designation of ownership of electrical facilities at the interface between the electric system and the nuclear plant and responsibilities for operational control coordination and maintenance of these facilities.
- R9.3.2.** Identification of any maintenance requirements for equipment not owned or controlled by the Nuclear Plant Generator Operator that are necessary to meet the NPIRs.
- R9.3.3.** Coordination of testing, calibration and maintenance of on-site and off-site power supply systems and related components.
- R9.3.4.** Provisions to address mitigating actions needed to avoid violating NPIRs and to address periods when responsible Transmission Entity loses the ability to assess the capability of the electric system to meet the NPIRs. These provisions shall include responsibility to notify the Nuclear Plant Generator Operator within a specified time frame.
- R9.3.5.** Provision for considering, within the restoration process, the requirements and urgency of a nuclear plant that has lost all off-site and on-site AC power.
- R9.3.6.** Coordination of physical and cyber security protection of the Bulk Electric System at the nuclear plant interface to ensure each asset is covered under at least one entity's plan.
- R9.3.7.** Coordination of the NPIRs with transmission system [Special Protection System Remedial Action Schemes](#) and underfrequency and undervoltage load shedding programs.
- R9.4.** Communications and training:
 - R9.4.1.** Provisions for communications between the Nuclear Plant Generator Operator and Transmission Entities, including communications protocols, notification time requirements, and definitions of terms.
 - R9.4.2.** Provisions for coordination during an off-normal or emergency event affecting the NPIRs, including the need to provide timely information explaining the event, an estimate of when the system will be returned to a normal state, and the actual time the system is returned to normal.
 - R9.4.3.** Provisions for coordinating investigations of causes of unplanned events affecting the NPIRs and developing solutions to minimize future risk of such events.
 - R9.4.4.** Provisions for supplying information necessary to report to government agencies, as related to NPIRs.
 - R9.4.5.** Provisions for personnel training, as related to NPIRs.

C. Measures

- M1.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide a copy of the transmittal and receipt of transmittal of the proposed NPIRs to the responsible Transmission Entities. (Requirement 1)
- M2.** The Nuclear Plant Generator Operator and each Transmission Entity shall each have a copy of the Agreement(s) addressing the elements in Requirement 9 available for inspection upon request of the Compliance Enforcement Authority. (Requirement 2 and 9)

- M3.** Each Transmission Entity responsible for planning analyses in accordance with the Agreement shall, upon request of the Compliance Enforcement Authority, provide a copy of the planning analyses results transmitted to the Nuclear Plant Generator Operator, showing incorporation of the NPIRs. The Compliance Enforcement Authority shall refer to the Agreements developed in accordance with this standard for specific requirements. (Requirement 3)
- M4.** Each Transmission Entity responsible for operating the electric system in accordance with the Agreement shall demonstrate or provide evidence of the following, upon request of the Compliance Enforcement Authority:
 - M4.1** The NPIRs have been incorporated into the current operating analysis of the electric system. (Requirement 4.1)
 - M4.2** The electric system was operated to meet the NPIRs. (Requirement 4.2)
 - M4.3** The Transmission Entity informed the Nuclear Plant Generator Operator when it became aware it lost the capability to assess the operation of the electric system affecting the NPIRs. (Requirement 4.3)
- M5.** The Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, demonstrate or provide evidence that the Nuclear Power Plant is being operated consistent with the Agreements developed in accordance with this standard. (Requirement 5)
- M6.** The Transmission Entities and Nuclear Plant Generator Operator shall, upon request of the Compliance Enforcement Authority, provide evidence of the coordination between the Transmission Entities and the Nuclear Plant Generator Operator regarding outages and maintenance activities which affect the NPIRs. (Requirement 6)
- M7.** The Nuclear Plant Generator Operator shall provide evidence that it informed the applicable Transmission Entities of changes to nuclear plant design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Transmission Entities to meet the NPIRs. (Requirement 7)
- M8.** The Transmission Entities shall each provide evidence that it informed the Nuclear Plant Generator Operator of changes to electric system design, configuration, operations, limits, Protection Systems, or capabilities that would impact the ability of the Nuclear Plant Generator Operator to meet the NPIRs. (Requirement 8)

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Enforcement Authority**

Regional Entity.
 - 1.2. Compliance Monitoring Period and Reset Time Frame**

Not applicable.
 - 1.3. Compliance Monitoring and Enforcement Processes:**
 - Compliance Audits
 - Self-Certifications
 - Spot Checking
 - Compliance Violation Investigations
 - Self-Reporting

Complaints

1.4. Data Retention

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- For Measure 1, the Nuclear Plant Generator Operator shall keep its latest transmittals and receipts.
- For Measure 2, the Nuclear Plant Generator Operator and each Transmission Entity shall have its current, in-force agreement.
- For Measure 3, the Transmission Entity shall have the latest planning analysis results.
- For Measures 4.3, 6 and 8, the Transmission Entity shall keep evidence for two years plus current.
- For Measures 5, 6 and 7, the Nuclear Plant Generator Operator shall keep evidence for two years plus current.

If a Responsible Entity is found non-compliant it shall keep information related to the noncompliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

- 2.1. Lower:** Agreement(s) exist per this standard and NPIRs were identified and implemented, but documentation described in M1-M8 was not provided.
- 2.2. Moderate:** Agreement(s) exist per R2 and NPIRs were identified and implemented, but one or more elements of the Agreement in R9 were not met.
- 2.3. High:** One or more requirements of R3 through R8 were not met.
- 2.4. Severe:** No proposed NPIRs were submitted per R1, no Agreement exists per this standard, or the Agreements were not implemented.

E. Regional Differences

The design basis for Canadian (CANDU) NPPs does not result in the same licensing requirements as U.S. NPPs. NRC design criteria specifies that in addition to emergency on-site electrical power, electrical power from the electric network also be provided to permit safe shutdown. This requirement is specified in such NRC Regulations as 10 CFR 50 Appendix A — General Design Criterion 17 and 10 CFR 50.63 Loss of all alternating current power. There are no equivalent Canadian Regulatory requirements for Station Blackout (SBO) or coping times as they do not form part of the licensing basis for CANDU NPPs.

Therefore the definition of NPLR for Canadian CANDU units will be as follows:

Nuclear Plant Licensing Requirements (NPLR) are requirements included in the design basis of the nuclear plant and are statutorily mandated for the operation of the plant; when used in this

Standard NUC-001-2.1(X) — Nuclear Plant Interface Coordination

standard, NPLR shall mean nuclear power plant licensing requirements for avoiding preventable challenges to nuclear safety as a result of an electric system disturbance, transient, or condition.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	May 2, 2007	Approved by Board of Trustees	New
2	To be determined	Modifications for Order 716 to Requirement R9.3.5 and footnote 1; modifications to bring compliance elements into conformance with the latest version of the ERO Rules of Procedure.	Revision
2	August 5, 2009	Adopted by Board of Trustees	Revised
2	January 22, 2010	Approved by FERC on January 21, 2010 Added Effective Date	Update
2	February 7, 2013	R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2.1	April 11, 2012	Errata approved by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
2.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
2.1	November 21, 2013	R9.1, R9.1.1, R9.1.2, R9.1.3, and R9.1.4 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
<u>2.1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** System Protection Coordination
2. **Number:** PRC-001-1.1(X)
3. **Purpose:**
To ensure system protection is coordinated among operating entities.
4. **Applicability**
 - 4.1. Balancing Authorities
 - 4.2. Transmission Operators
 - 4.3. Generator Operators
5. **Effective Date:** January 1, 2007

B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.
- R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:
 - R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.
 - R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.
- R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.
 - R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
 - R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.
- R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.
- R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Remedial Action Schemes. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will

have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. **Levels of Non-Compliance for Balancing Authorities:**

4.1. **Level 1:** Not applicable.

4.2. **Level 2:** Not applicable.

4.3. **Level 3:** Not applicable.

4.4. **Level 4:** Did not monitor the status of each Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** System Protection Coordination

2. **Number:** PRC-001-1.1(X)

3. **Purpose:**

To ensure system protection is coordinated among operating entities.

4. **Applicability**

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

- R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
- R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.
- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each ~~Special Protection System~~Remedial Action Scheme in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

- M1.** Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.
- M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the ~~Special Protection System~~Remedial Action Schemes in its area. (Requirement 6 Part 1)
- M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its ~~Special Protection System~~Remedial Action Schemes. (Requirement 6 Part 2)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)

- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Generator Operators:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.

3. Levels of Non-Compliance for Transmission Operators:

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.

3.4.2 Did not monitor the status of each ~~Special Protection System~~Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

4. Levels of Non-Compliance for Balancing Authorities:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: Did not monitor the status of each ~~Special Protection System~~Remedial Action Scheme, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1.1	April 11, 2012	Errata adopted by the Standards Committee; (Capitalized “Protection System” in accordance with Implementation Plan for Project 2007-17 approval of revised definition of “Protection System”)	Errata associated with Project 2007-17
1.1	September 9, 2013	Informational filing submitted to reflect the revised definition of Protection System in accordance with the Implementation Plan for the revised term.	
1.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-1(X)
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. Applicability

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
 - 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
 - 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** On the first day of the second quarter following applicable regulatory approval.

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
 - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
 - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the

Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
 - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
 - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
 - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
 - R2.3.2.** When FERAS is not available, then
 - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
 - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
 - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
 - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to

WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
- R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
 - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
 - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
 - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
 - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
 - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
 - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
 - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
 - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
 - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
 - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
 - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

M2.4.2 Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

M3. Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

M3.1 Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

M3.2 Completion of repair or replacement of Protection System and/or RAS that misoperated.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 The Performance-reset Period is one calendar month.

1.3 Data Retention

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

Lower	Moderate	High	Severe
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WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation

System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.
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R2.1 and R2.2.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.3

Lower	Moderate	High	Severe
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.2.2 and R2.4

Lower	Moderate	High	Severe

WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation

The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.
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R3.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

R3.2

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1	

WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation

1	April 21, 2011	FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011)	
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

- 1. Title:** Protection System and Remedial Action Scheme Misoperation
- 2. Number:** PRC-004-WECC-1(X)
- 3. Purpose:** Regional Reliability Standard to ensure all transmission and generation Protection System and Remedial Action Scheme (RAS) Misoperations on Transmission Paths and RAS defined in section 4 are analyzed and/or mitigated.

4. Applicability

- 4.1.** Transmission Owners of selected WECC major transmission path facilities and RAS listed in tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.2.** Generator Owners that own RAS listed in the Table titled “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 4.3.** Transmission Operators that operate major transmission path facilities and RAS listed in Tables titled “Major WECC Transfer Paths in the Bulk Electric System” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20Paths%204-28-08.pdf> and “Major WECC Remedial Action Schemes (RAS)” provided at <http://www.wecc.biz/Standards/Approved%20Standards/Supporting%20Tables/Table%20Major%20RAS%204-28-08.pdf>.
- 5. Effective Date:** On the first day of the second quarter following applicable regulatory approval.

B. Requirements

The requirements below only apply to the major transmission paths facilities and RAS listed in the tables titled “Major WECC Transfer Paths in the Bulk Electric System” and “Major WECC Remedial Action Schemes (RAS).”

- R.1.** System Operators and System Protection personnel of the Transmission Owners and Generator Owners shall analyze all Protection System and RAS operations. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
 - R1.1.** System Operators shall review all tripping of transmission elements and RAS operations to identify apparent Misoperations within 24 hours.
 - R1.2.** System Protection personnel shall analyze all operations of Protection Systems and RAS within 20 business days for correctness to characterize whether a Misoperation has occurred that may not have been identified by System Operators.
- R.2.** Transmission Owners and Generator Owners shall perform the following actions for each Misoperation of the Protection System or RAS. It is not intended that Requirements R2.1 through R2.4 apply to Protection System and/or RAS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with NERC Reliability Standards. If the Transmission Owner or Generator Owner later finds the Protection System or RAS operation to be incorrect through System Protection personnel analysis, the requirements of R2.1 through R2.4 become applicable at the time the

Transmission Owner or Generator Owner identifies the Misoperation:

- R2.1.** If the Protection System or RAS has a Security-Based Misoperation and two or more Functionally Equivalent Protection Systems (FEPS) or Functionally Equivalent RAS (FERAS) remain in service to ensure Bulk Electric System (BES) reliability, the Transmission Owners or Generator Owners shall remove from service the Protection System or RAS that misoperated within 22 hours following identification of the Misoperation. Repair or replacement of the failed Protection System or RAS is at the Transmission Owners' and Generator Owners' discretion. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
- R2.2.** If the Protection System or RAS has a Security-Based Misoperation and only one FEPS or FERAS remains in service to ensure BES reliability, the Transmission Owner or Generator Owner shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
 - R2.2.1.** Following identification of the Protection System or RAS Misoperation, Transmission Owners and Generator Owners shall remove from service within 22 hours for repair or modification the Protection System or RAS that misoperated.
 - R2.2.2.** The Transmission Owner or Generator Owner shall repair or replace any Protection System or RAS that misoperated with a FEPS or FERAS within 20 business days of the date of removal. The Transmission Owner or Generator Owner shall remove the Element from service or disable the RAS if repair or replacement is not completed within 20 business days.
- R2.3.** If the Protection System or RAS has a Security-Based or Dependability-Based Misoperation and a FEPS and FERAS is not in service to ensure BES reliability, Transmission Owners or Generator Owners shall repair and place back in service within 22 hours the Protection System or RAS that misoperated. If this cannot be done, then Transmission Owners and Generator Owners shall perform the following. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*
 - R2.3.1.** When a FEPS is not available, the Transmission Owners shall remove the associated Element from service.
 - R2.3.2.** When FERAS is not available, then
 - 2.3.2.1.** The Generator Owners shall adjust generation to a reliable operating level, or
 - 2.3.2.2.** Transmission Operators shall adjust the SOL and operate the facilities within established limits.
- R2.4.** If the Protection System or RAS has a Dependability-Based Misoperation but has one or more FEPS or FERAS that operated correctly, the associated Element or transmission path may remain in service without removing from service the Protection System or RAS that failed, provided one of the following is performed.
 - R2.4.1.** Transmission Owners or Generator Owners shall repair or replace any Protection System or RAS that misoperated with FEPS and FERAS within 20 business days of the date of the Misoperation identification, or
 - R2.4.2.** Transmission Owners or Generator Owners shall remove from service the associated Element or RAS. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*
- R.3.** Transmission Owners and Generation Owners shall submit Misoperation incident reports to

WECC within 10 business days for the following. *[Violation Risk Factor: Lower] [Time Horizon: Operations Assessment]*

- R3.1.** Identification of a Misoperation of a Protection System and/or RAS,
- R3.2.** Completion of repairs or the replacement of Protection System and/or RAS that misoperated.

C. Measures

Each measure below applies directly to the requirement by number.

- M1.** Transmission Owners and Generation Owners shall have evidence that they reported and analyzed all Protection System and RAS operations.
 - M1.1** Transmission Owners and Generation Owners shall have evidence that System Operating personnel reviewed all operations of Protection System and RAS within 24 hours.
 - M1.2** Transmission Owners and Generation Owners shall have evidence that System Protection personnel analyzed all operations of Protection System and RAS for correctness within 20 business days.
- M2.** Transmission Owners and Generation Owners shall have evidence for the following.
 - M2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
 - M2.2** Transmission Owners and Generation Owners shall have evidence that they removed from service and repaired the Protection System or RAS that misoperated per measurements M2.2.1 through M2.2.2.
 - M2.2.1** Transmission Owners and Generation Owners shall have evidence that they removed the Protection System or RAS that misoperated from service within 22 hours following identification of the Protection System or RAS Misoperation.
 - M2.2.2** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days or either removed the Element from service or disabled the RAS.
 - M2.3** The Transmission Owners and Generation Owners shall have evidence that they repaired the Protection System or RAS that misoperated within 22 hours following identification of the Protection System or RAS Misoperation.
 - M2.3.1** The Transmission Owner shall have evidence that it removed the associated Element from service.
 - M2.3.2** The Generator Owners and Transmission Operators shall have documentation describing all actions taken that adjusted generation or SOLs and operated facilities within established limits.
 - M2.4** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated including documentation that describes the actions taken.
 - M2.4.1** Transmission Owners and Generation Owners shall have evidence that they repaired or replaced the Protection System or RAS that misoperated within 20 business days of the misoperation identification.

M2.4.2 Transmission Owners and Generation Owners shall have evidence that they removed the associated Element or RAS from service.

M3. Transmission Owners and Generation Owners shall have evidence that they reported the following within 10 business days.

M3.1 Identification of all Protection System and RAS Misoperations and corrective actions taken or planned.

M3.2 Completion of repair or replacement of Protection System and/or RAS that misoperated.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Monitoring Responsibility

Compliance Enforcement Authority

1.2 Compliance Monitoring Period

Compliance Enforcement Authority may use one or more of the following methods to assess compliance:

- Misoperation Reports
- Reports submitted quarterly
- Spot check audits conducted anytime with 30 days notice given to prepare
- Periodic audit as scheduled by the Compliance Enforcement Authority
- Investigations
- Other methods as provided for in the Compliance Monitoring Enforcement Program

1.2.1 The Performance-reset Period is one calendar month.

1.3 Data Retention

Reliability Coordinators, Transmission Owners, and Generation Owners shall keep evidence for Measures M1 and M2 for five calendar years plus year to date.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R1

Lower	Moderate	High	Severe
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WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation

System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System Operation or RAS operation within 24 hours but did review the Protection System Operation or RAS operation within six business days.	System Operating personnel of the Transmission Owner or Generator Owner did not review the Protection System operation or RAS operation within six business days.	System Protection personnel of the Transmission Owner and Generator Owner did not analyze the Protection System operation or RAS operation within 20 business days but did analyze the Protection System operation or RAS operation within 25 business days.	System Protection personnel of the Transmission Owner or Generator Owner did not analyze the Protection System operation or RAS operation within 25 business days.
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R2.1 and R2.2.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Owner and Generator Owner did not remove from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Owner and Generator Owner did not perform the removal from service, repair, or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.3

Lower	Moderate	High	Severe
The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 22 hours but did perform the requirements within 24 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 24 hours but did perform the requirements within 28 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required in less than 28 hours but did perform the requirements within 32 hours.	The Transmission Operator and Generator Owner did not adjust generation to a reliable operating level, adjust the SOL and operate the facilities within established limits or implement other compliance measures for the Protection System or RAS that misoperated as required within 32 hours.

R2.2.2 and R2.4

Lower	Moderate	High	Severe

WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation

The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 25 business days but did perform the required activities within 28 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustment to comply with the requirements within 28 business days but did perform the required activities within 30 business days.	The Transmission Owner and Generator Owner did not perform the required repairs, replacement, or system operation adjustments to comply with the requirements within 30 business days.
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R3.1

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 10 business days but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 15 business days but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 20 business days but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the Misoperation and corrective actions taken or planned to comply with the requirements within 25 business days.

R3.2

Lower	Moderate	High	Severe
The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 10 business days of the completion but did perform the required activities within 15 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 15 business days of the completion but did perform the required activities within 20 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 20 business days of the completion but did perform the required activities within 25 business days.	The Transmission Owner and Generator Owner did not report the completion of repair or replacement of Protection System and/or RAS that misoperated to comply with the requirements within 25 business days of the completion.

Version History — Shows Approval History and Summary of Changes in the Action Field

Version	Date	Action	Change Tracking
1	April 16, 2008	Permanent Replacement Standard for PRC-STD-001-1 and PRC-STD-003-1	

WECC Standard PRC-004-WECC-1(X) — Protection System and Remedial Action Scheme Misoperation

1	April 21, 2011	FERC Order issued approving PRC-004-WECC-1 (approval effective June 27, 2011)	
<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.
 - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
 - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
 - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** See Implementation Plan

B. Requirements

- R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Component Type - Any one of the five specific elements of the Protection System definition.

Component – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

Unresolved Maintenance Issue - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

- 1. Compliance Monitoring Process**

 - 1.1. Compliance Enforcement Authority**

 - Regional Entity
 - 1.2. Compliance Monitoring and Enforcement Processes:**

 - Compliance Audit
 - Self-Certification
 - Spot Checking
 - Compliance Investigation
 - Self-Reporting
 - Complaint

1.3. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with less than 60 Components <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, <p style="text-align: center;">OR</p>

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, <li style="text-align: center;">OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15	The responsible entity failed to undertake efforts to correct greater

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	fewer identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(X) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

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1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
2(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ¹	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2). 	12 calendar years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

¹ For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ¹	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 calendar months	Verify that the communications system is functional.
	6 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 calendar years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e)

Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RASs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 calendar years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	<p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. <p>Alarming for power supply failure (See Table 2).</p>	12 calendar years	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). <p>Alarming for change of settings (See Table 2).</p>	12 calendar years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

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Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 calendar years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 calendar years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 calendar years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 calendar years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

Countable Event – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

A. Introduction

1. **Title:** Protection System Maintenance
2. **Number:** PRC-005-2(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a ~~Special Protection System (SPS)~~ Remedial Action Scheme (RAS) for BES reliability.
 - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
 - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
 - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
5. **Effective Date:** See Implementation Plan

B. Requirements

- R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Component Type - Any one of the five specific elements of the Protection System definition.

Component – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

Unresolved Maintenance Issue - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

- 1. Compliance Monitoring Process**

 - 1.1. Compliance Enforcement Authority**

 - Regional Entity
 - 1.2. Compliance Monitoring and Enforcement Processes:**

 - Compliance Audit
 - Self-Certification
 - Spot Checking
 - Compliance Investigation
 - Self-Reporting
 - Complaint

1.3. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 3) Maintained a Segment with less than 60 Components <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, <p style="text-align: center;">OR</p>

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<ul style="list-style-type: none"> • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, <li style="text-align: center;">OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15	The responsible entity failed to undertake efforts to correct greater

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	fewer identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	identified Unresolved Maintenance Issues.	than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2(X) Protection System Maintenance Supplementary Reference and FAQ — July 2012.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

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1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
<u>2(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ¹	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2). 	12 calendar years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

¹ For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ¹	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 calendar months	Verify that the communications system is functional.
	6 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 calendar years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b)

**Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for SPSRAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c)

**Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)**

Protection System Station dc supply used only for non-BES interrupting devices for SPSRAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPSRAS , non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e)

Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for **SPSRAS**, non-distributed UFLS, and non-distributed UVLS systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPSRAS , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and <u>SPSRAS</u>s except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 calendar years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with <u>SPSRAS</u> .	12 calendar years	Verify all paths of the control circuits essential for proper operation of the <u>SPSRAS</u> .
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or <u>SPSRAS</u> whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	<p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. <p>Alarming for power supply failure (See Table 2).</p>	12 calendar years	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). <p>Alarming for change of settings (See Table 2).</p>	12 calendar years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

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Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 calendar years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 calendar years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 calendar years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 calendar years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

Countable Event – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

A. Introduction

- 1. Title:** Protection System and Automatic Reclosing Maintenance
- 2. Number:** PRC-005-3(X)
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Remedial Action Schemes (RAS) for BES reliability.
 - 4.2.5** Protection Systems for generator Facilities that are part of the BES, including:
 - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
 - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6** Automatic Reclosing¹, including:
 - 4.2.6.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of a RAS specified in Section 4.2.4.

5. Effective Date: See Implementation Plan

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate

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monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.3. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

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The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

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2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p>

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

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1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
3(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a) Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3) Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with RAS. (See Table 4-2(b) for RAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the RAS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

<p align="center">Table 2 – Alarming Paths and Monitoring</p> <p align="center">In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p>	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
<p>Alarm Path with monitoring:</p> <p>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.</p>	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

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Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a RAS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a RAS.	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of a RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of a RAS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of a RAS (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of a RAS.	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS.
Control circuitry associated with Automatic Reclosing that is an integral part of a RAS whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

A. Introduction

1. **Title:** Protection System and Automatic Reclosing Maintenance
2. **Number:** PRC-005-3(X)
3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems and Automatic Reclosing affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Generator Owner
 - 4.1.3 Distribution Provider
 - 4.2. **Facilities:**
 - 4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2 Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3 Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4 Protection Systems installed as a [Special Protection System \(SPS\) Remedial Action Schemes \(RAS\)](#) for BES reliability.
 - 4.2.5 Protection Systems for generator Facilities that are part of the BES, including:
 - 4.2.5.1 Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
 - 4.2.5.2 Protection Systems for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3 Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4 Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
 - 4.2.6 Automatic Reclosing¹, including:
 - 4.2.6.1 Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed

¹ Automatic Reclosing addressed in Section 4.2.6.1 and 4.2.6.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest BES generating unit within the Balancing Authority Area where the Automatic Reclosing is applied.

gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area.

4.2.6.2 Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.6.1 when the substation is less than 10 circuit-miles from the generating plant substation.

4.2.6.3 Automatic Reclosing applied as an integral part of an [SPS](#) [RAS](#) specified in Section 4.2.4.

5. Effective Date: See Implementation Plan

6. Definitions Used in this Standard: The following terms are defined for use only within PRC-005-3, and should remain with the standard upon approval rather than being moved to the Glossary of Terms.

Automatic Reclosing – Includes the following Components:

- Reclosing relay
- Control circuitry associated with the reclosing relay.

Unresolved Maintenance Issue – A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

Segment – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

Component Type – Either any one of the five specific elements of the Protection System definition or any one of the two specific elements of the Automatic Reclosing definition.

Component – A Component is any individual discrete piece of equipment included in a Protection System or in Automatic Reclosing, including but not limited to a protective relay, reclosing relay, or current sensing device. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit Components. Another example of where the entity has some discretion on determining what constitutes a single Component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single Component.

Countable Event – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component or Automatic Reclosing configuration or application errors are not included in Countable Events.

B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems and Automatic Reclosing identified in Facilities Section 4.2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System and Automatic Reclosing Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
 - 1.2.** Include the applicable monitored Component attributes applied to each Protection System and Automatic Reclosing Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System and Automatic Reclosing Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System and Automatic Reclosing Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System and Automatic Reclosing Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System and Automatic Reclosing Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System and Automatic Reclosing Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate

monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, and Table 4-1 through 4-2. (Part 1.2)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System and Automatic Reclosing Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System and Automatic Reclosing Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Compliance Monitoring and Enforcement Processes:

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Investigation
- Self-Reporting
- Complaint

1.3. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Standard PRC-005-3(X) — Protection System and Automatic Reclosing Maintenance

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component, or all performances of each distinct maintenance activity for the Protection System or Automatic Reclosing Component since the previous scheduled audit date, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)</p>	<p>The responsible entity’s PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components. (Part 1.2).</p>	<p>The responsible entity failed to establish a PSMP.</p> <p style="text-align: center;">OR</p> <p>The responsible entity’s PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).</p>
R2	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.</p>	<p style="text-align: center;">NA</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.</p>	<p>The responsible entity uses performance-based maintenance intervals in its PSMP but:</p> <ol style="list-style-type: none"> 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP <p style="text-align: center;">OR</p> <ol style="list-style-type: none"> 2) Failed to reduce Countable Events to no more than 4% within five years <p style="text-align: center;">OR</p>

Standard PRC-005-3(X) — Protection System and Automatic Reclosing Maintenance

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				3) Maintained a Segment with less than 60 Components OR 4) Failed to: <ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the Segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.	For Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, and Tables 4-1 through 4-2.
R4	For Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific	For Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific

Standard PRC-005-3(X) — Protection System and Automatic Reclosing Maintenance

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.	Component Type in accordance with their performance-based PSMP.
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — March 2013.
2. Considerations for Maintenance and Testing of Autoreclosing Schemes — November 2012.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

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1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing	
3	November 7, 2013	Adopted by the NERC Board of Trustees	Revised to address the FERC directive in Order No.758 to include Automatic Reclosing in maintenance programs.
<u>3(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

² For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ²	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 Calendar Years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 Calendar Months	Verify that the communications system is functional.
	6 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 Calendar Years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 Calendar Years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 Calendar Years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for [SPSRAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for [SPSRAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPSRAS , non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack

Table 1-4(b)
Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for [SPSRAS](#), non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c)
 Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries
 Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d)
Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for **SPSRAS**, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e) Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPSRAS , non-distributed UFLS, and non-distributed UVLS systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPSRAS , non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3)		
Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSRAS except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPSRAS . (See Table 4-2(b) for SPSRAS which include Automatic Reclosing.)	12 Calendar Years	Verify all paths of the control circuits essential for proper operation of the SPSRAS .
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPSRAS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

<p align="center">Table 2 – Alarming Paths and Monitoring</p> <p align="center">In Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements</p>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
<p>Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below.</p> <p>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.</p>	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
<p>Alarm Path with monitoring:</p> <p>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.</p>	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 Calendar Years	<p>Verify that settings are as specified.</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate. <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. <p>Alarming for power supply failure (See Table 2).</p>	12 Calendar Years	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). <p>Alarming for change of settings (See Table 2).</p>	12 Calendar Years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

Standard PRC-005-3 — Protection System and Automatic Reclosing Maintenance

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 Calendar Years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 Calendar Years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 Calendar Years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

Table 4-1 Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Reclosing Relay		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored reclosing relay not having all the monitoring attributes of a category below.	6 Calendar Years	Verify that settings are as specified. For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.
Monitored microprocessor reclosing relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (See Table 2). • Alarming for power supply failure (See Table 2). 	12 Calendar Years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.

Table 4-2(a) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that are NOT an Integral Part of a SPS_RAS		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of a SPS_RAS .	12 Calendar Years	Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry.
Control circuitry associated with Automatic Reclosing that is not part of a SPS_RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2)	No periodic maintenance specified	None.

Table 4-2(b) Maintenance Activities and Intervals for Automatic Reclosing Components Component Type – Control Circuitry Associated with Reclosing Relays that ARE an Integral Part of an <u>SPS_RAS</u>		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an <u>SPS_RAS</u> (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device.
Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an <u>SPS_RAS</u> .	12 Calendar Years	Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the <u>SPS_RAS</u> .
Control circuitry associated with Automatic Reclosing that is an integral part of an <u>SPS_RAS</u> whose integrity is monitored and alarmed. (See Table 2)	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, and Tables 4-1 through 4-2 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-1(X)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
 - 4.1. Planning Coordinators
 - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
 - 4.2.1 Transmission Owners
 - 4.2.2 Distribution Providers
 - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **(Proposed) Effective Date:**
 - 5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.
 - 5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1(X), but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(X).

B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
 - 2.1. Those islands selected by applying the criteria in Requirement R1, and

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme, and
 - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
 - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
 - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
 - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
 - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
 - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the

- Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
 - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
 - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
 - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
 - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
 - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
 - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
 - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
 - 11.1.** The performance of the UFLS equipment,
 - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a

UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	<p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>	<p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>	<p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>
R2	N/A	<p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>	<p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>	<p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	<p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p>	<p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p>	<p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p>
R4	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2</p>
R5	N/A	N/A	N/A	<p>The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.</p>
R6	N/A	N/A	N/A	<p>The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.</p>
R7	<p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.</p>	<p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.</p>	<p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.</p>	<p>The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>	<p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>	<p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>	<p>Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>
<p>R11</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.</p> <p>OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			specified in Requirement R11, Parts 11.1 or 11.2.	The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, of up to 25 percent within the identified island(s).
[VRF: High][Time Horizon: Long-term Planning]

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Remedial Action Scheme.

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	<p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p>	<p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p>	<p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p>
E.B.2	N/A	N/A	<p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>	<p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.
E.B.3	N/A	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions	The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.
E.B.4	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island	The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>	<p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>	<p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>	<p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p>
E.B.11	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p>	<p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p>
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p>	<p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p>	<p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p>

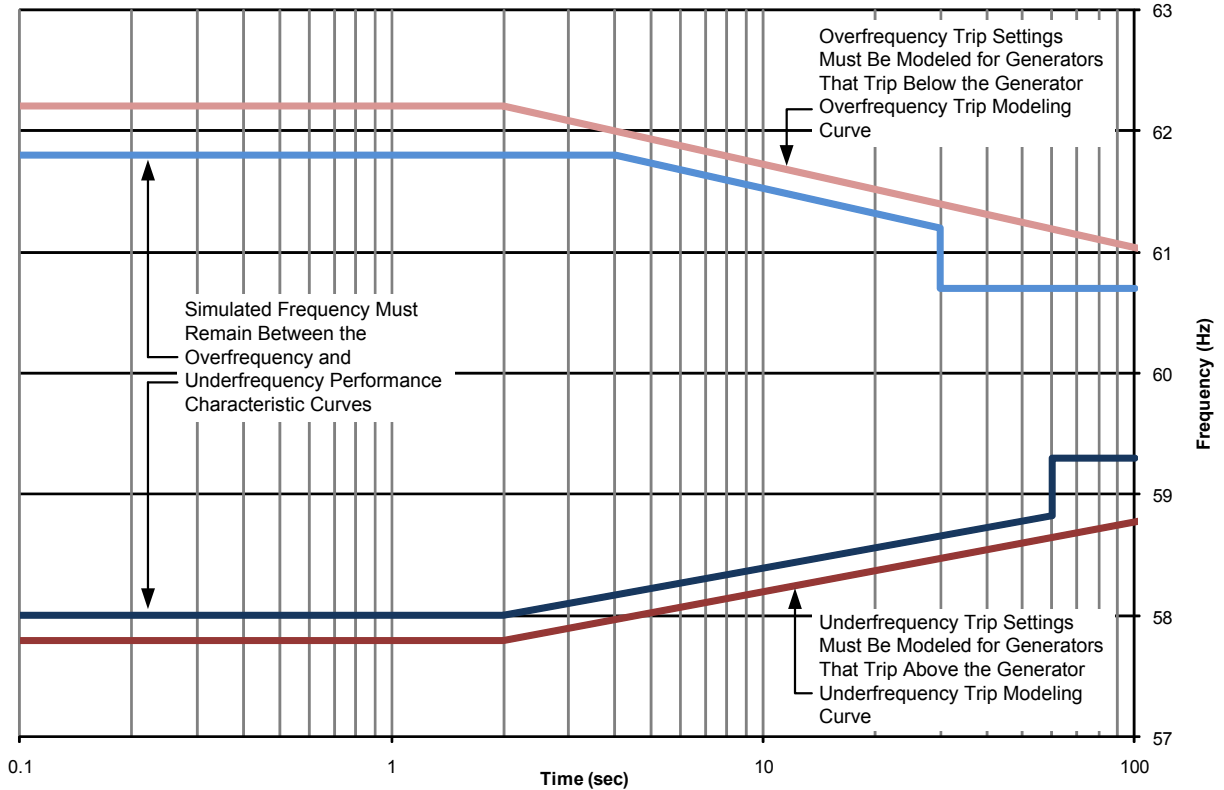
Associated Documents

Version History

Version	Date	Action	Change Tracking
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

PRC-006-1(X) – Attachment 1

Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6

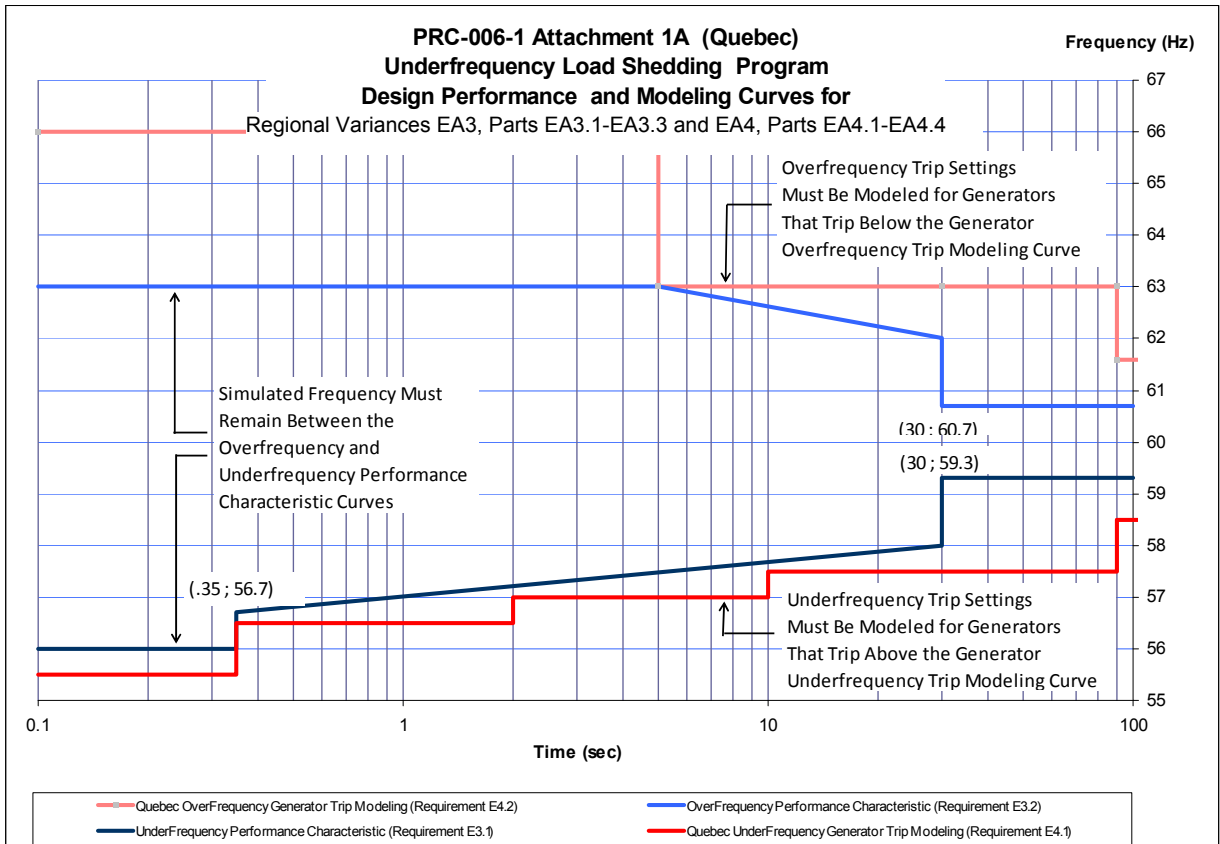


□□□□	Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
□□□□	Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
□□□□	Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
□□□□	Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 4 \text{ s}$	$4 \text{ s} < t \leq 30 \text{ s}$	$t > 30 \text{ s}$
$f = 62.2 \text{ Hz}$	$f = -0.686\log(t) + 62.41 \text{ Hz}$	$f = 61.8 \text{ Hz}$	$f = -0.686\log(t) + 62.21 \text{ Hz}$	$f = 60.7 \text{ Hz}$

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 2 \text{ s}$	$2 \text{ s} < t \leq 60 \text{ s}$	$t > 60 \text{ s}$
$f = 57.8 \text{ Hz}$	$f = 0.575\log(t) + 57.63 \text{ Hz}$	$f = 58.0 \text{ Hz}$	$f = 0.575\log(t) + 57.83 \text{ Hz}$	$f = 59.3 \text{ Hz}$



A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-1(X)
3. **Purpose:** To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.
4. **Applicability:**
 - 4.1. Planning Coordinators
 - 4.2. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the Planning Coordinators. Such entities may include one or more of the following:
 - 4.2.1 Transmission Owners
 - 4.2.2 Distribution Providers
 - 4.3. Transmission Owners that own Elements identified in the UFLS program established by the Planning Coordinators.
5. **(Proposed) Effective Date:**
 - 5.1. The standard, with the exception of Requirement R4, Parts 4.1 through 4.6, is effective the first day of the first calendar quarter one year after applicable regulatory approvals.
 - 5.2. Parts 4.1 through 4.6 of Requirement R4 shall become effective and enforceable one year following the receipt of generation data as required in PRC-024-1(X), but no sooner than one year following the first day of the first calendar quarter after applicable regulatory approvals of PRC-006-1(X).

B. Requirements

- R1. Each Planning Coordinator shall develop and document criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES), including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands. [*VRF: Medium*][*Time Horizon: Long-term Planning*]
- R2. Each Planning Coordinator shall identify one or more islands to serve as a basis for designing its UFLS program including: [*VRF: Medium*][*Time Horizon: Long-term Planning*]
 - 2.1. Those islands selected by applying the criteria in Requirement R1, and

- 2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or [Special Protection System Remedial Action Scheme](#), and
 - 2.3. A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides. If a Planning Coordinator's area resides in multiple Regional Entity areas, each of those Regional Entity areas shall be identified as an island. Planning Coordinators may adjust island boundaries to differ from Regional Entity area boundaries by mutual consent where necessary for the sole purpose of producing contiguous regional islands more suitable for simulation.
- R3.** Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). [*VRF: High*][*Time Horizon: Long-term Planning*]
- 3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
 - 3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
 - 3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:
 - 3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
 - 3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
 - 3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- R4.** Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following: [*VRF: High*][*Time Horizon: Long-term Planning*]
- 4.1. Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the

- Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- 4.2. Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
 - 4.3. Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
 - 4.4. Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
 - 4.5. Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
 - 4.6. Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
 - 4.7. Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- R5. Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island through one of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
 - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
 - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet

Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island and the ERO.

- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within its Interconnection within 30 calendar days of a request. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. *[VRF: Lower][Time Horizon: Long-term Planning]*
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission. *[VRF: High][Time Horizon: Long-term Planning]*
- R11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall conduct and document an assessment of the event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*
 - 11.1.** The performance of the UFLS equipment,
 - 11.2.** The effectiveness of the UFLS program.
- R12.** Each Planning Coordinator, in whose islanding event assessment (per R11) UFLS program deficiencies are identified, shall conduct and document a UFLS design assessment to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*
- R13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall coordinate its event assessment (in accordance

with Requirement R11) with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event through one of the following: *[VRF: Medium][Time Horizon: Operations Assessment]*

- Conduct a joint event assessment per Requirement R11 among the Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 that reaches conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, or
- Conduct an independent event assessment per Requirement R11 and where the assessment fails to reach conclusions and recommendations consistent with those of the event assessments of the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event, identify differences in the assessments that likely resulted in the differences in the conclusions and recommendations and report these differences to the other Planning Coordinators whose areas or portions of whose areas were included in the same islanding event and the ERO.

R14. Each Planning Coordinator shall respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following *[VRF: Lower][Time Horizon: Long-term Planning]*:

14.1. UFLS program, including a schedule for implementation

14.2. UFLS design assessment

14.3. Format and schedule of UFLS data submittal

C. Measures

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s) as a basis for designing a UFLS program that meet the criteria in Requirement R2, Parts 2.1 through 2.3.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3, Parts 3.1 through 3.3.

- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4, Parts 4.1 through 4.7.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within their Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.
- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R11.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a

UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.

- M13.** Each Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency excursions below the initializing set points of the UFLS program, shall have dated evidence such as a joint assessment report, independent assessment reports and letters describing likely reasons for differences in conclusions and recommendations, or other dated documentation demonstrating it coordinated its event assessment (per Requirement R11) with all other Planning Coordinator(s) whose areas or portions of whose areas were also included in the same islanding event per Requirement R13.
- M14.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program per Requirement R14.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R14, Measures M1, M2, M3, M4, M5, M12, and M14 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to another Planning Coordinator since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.

- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.
- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	<p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas that may form islands.</p> <p>OR</p> <p>The Planning Coordinator developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>	<p>The Planning Coordinator developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>	<p>The Planning Coordinator failed to develop and document criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas and Regional Entity areas, that may form islands.</p>
R2	N/A	<p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include one (1) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>	<p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include two (2) of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p>	<p>The Planning Coordinator identified an island(s) to serve as a basis for designing its UFLS program but failed to include all of the Parts as specified in Requirement R2, Parts 2.1, 2.2, or 2.3.</p> <p>OR</p> <p>The Planning Coordinator failed to identify any island(s) to serve as a basis for designing its UFLS program.</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	<p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet one (1) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p>	<p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet two (2) of the performance characteristic in Requirement R3, Parts 3.1, 3.2, or 3.3 in simulations of underfrequency conditions.</p>	<p>The Planning Coordinator developed a UFLS program including notification of and a schedule for implementation by UFLS entities within its area where imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s), but failed to meet all the performance characteristic in Requirement R3, Parts 3.1, 3.2, and 3.3 in simulations of underfrequency conditions.</p> <p>OR</p> <p>The Planning Coordinator failed to develop a UFLS program including notification of and a schedule for implementation by UFLS entities within its area</p>
R4	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include two (2) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include three (3) of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p>	<p>The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 but simulation failed to include four (4) or more of the items as specified in Requirement R4, Parts 4.1 through 4.7.</p> <p>OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement R3 for each island identified in Requirement R2
R5	N/A	N/A	N/A	The Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator which includes multiple Planning Coordinator areas or portions of those areas, failed to coordinate its UFLS program design through one of the manners described in Requirement R5.
R6	N/A	N/A	N/A	The Planning Coordinator failed to maintain a UFLS database for use in event analyses and assessments of the UFLS program at least once each calendar year, with no more than 15 months between maintenance activities.
R7	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 30 calendar days and up to and including 40 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 40 calendar days but less than and including 50 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 50 calendar days but less than and including 60 calendar days following the request.	The Planning Coordinator provided its UFLS database to other Planning Coordinators more than 60 calendar days following the request. OR

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The Planning Coordinator failed to provide its UFLS database to other Planning Coordinators.
R8	The UFLS entity provided data to its Planning Coordinator(s) less than or equal to 10 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 10 calendar days but less than or equal to 15 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity provided data to its Planning Coordinator(s) but the data was not according to the format specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 15 calendar days but less than or equal to 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.	The UFLS entity provided data to its Planning Coordinator(s) more than 20 calendar days following the schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database. OR The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 95% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 90% but more than (and including) 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Planning Coordinator(s) area in which it owns assets.
R10	The Transmission Owner provided less than 100% but more than (and including) 95% automatic switching	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks,

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>	<p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>	<p>of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>	<p>Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission</p>
<p>R11</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate one (1) of the Parts as</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event and evaluated the parts as specified in Requirement R11, Parts 11.1 and 11.2 within a time greater than 15 months of actuation.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to conduct and document an assessment of the event and evaluate the Parts as specified in Requirement R11, Parts 11.1 and 11.2.</p> <p>OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			specified in Requirement R11, Parts 11.1 or 11.2.	The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, conducted and documented an assessment of the event within one year of event actuation but failed to evaluate all of the Parts as specified in Requirement R11, Parts 11.1 and 11.2.
R12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than two years but less than or equal to 25 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 25 months but less than or equal to 26 months of event actuation.	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than 26 months of event actuation. OR The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R11, failed to conduct and document a UFLS design assessment to consider the identified deficiencies.
R13	N/A	N/A	N/A	The Planning Coordinator, in whose area a BES islanding event occurred that also included the area(s) or portions of area(s) of other Planning Coordinator(s) in the same islanding event and that resulted in system frequency

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				excursions below the initializing set points of the UFLS program, failed to coordinate its UFLS event assessment with all other Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event in one of the manners described in Requirement R13
R14	N/A	N/A	N/A	The Planning Coordinator failed to respond to written comments submitted by UFLS entities and Transmission Owners within its Planning Coordinator area following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes were made or reasons why changes were not made to the items in Parts 14.1 through 14.3.

E. Regional Variances

E.A. Regional Variance for the Quebec Interconnection

The following Interconnection-wide variance shall be applicable in the Quebec Interconnection and replaces, in their entirety, Requirements R3 and R4 and the violation severity levels associated with Requirements R3 and R4.

E.A.3. Each Planning Coordinator shall develop a UFLS program, including a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, of up to 25 percent within the identified island(s).
[VRF: High][Time Horizon: Long-term Planning]

E.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.A.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

EA.3.3.1. Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES

EA.3.3.2. Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES

EA.3.3.3. Facilities consisting of one or more units connected to the BES at a common bus with total generation above 50 MVA gross nameplate rating.

E.A.4. Each Planning Coordinator shall conduct and document a UFLS design assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*

E.A.4.1 Underfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly

connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1A, and

E.A.4.2 Overfrequency trip settings of individual generating units that are part of plants/facilities with a capacity of 50 MVA or more individually or cumulatively (gross nameplate rating), directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 2A, and

E.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.E.A.3. Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.A.3 Parts E.A.3.1 through EA3.3.

M.E.A.4. Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement E.A.4 Parts E.A.4.1 through E.A.4.3.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
EA3	N/A	The Planning Coordinator developed a UFLS program, including a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Parts E.A.3.1, E.A.3.2, or E.A.3.3 in simulations of underfrequency conditions	The Planning Coordinator developed a UFLS program including a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Parts E.A.3.1, E.A.3.2, and E.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
EA4	N/A	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3 but simulation failed to include one (1) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include two (2) of the items as specified in Parts E.A.4.1, E.A.4.2 or E.A.4.3.	The Planning Coordinator conducted and documented a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E3 but simulation failed to include all of the items as specified in Parts E.A.4.1, E.A.4.2 and E.A.4.3. OR The Planning Coordinator failed to conduct and document a UFLS assessment at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.A.3

E.B. Regional Variance for the Western Electricity Coordinating Council

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R1, R2, R3, R4, R5, R11, R12, and R13.

E.B.1. Each Planning Coordinator shall participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that develops and documents criteria, including consideration of historical events and system studies, to select portions of the Bulk Electric System (BES) that may form islands. *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per E.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

E.B.2.1. Those islands selected by applying the criteria in Requirement E.B.1, and

E.B.2.2. Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or [Special Protection System Remedial Action Scheme](#).

EB.3. Each Planning Coordinator shall adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*

E.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-1(X) - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

E.B.3.3. Volts per Hz (V/Hz) shall not exceed 1.18 per unit for longer than two seconds cumulatively per simulated event, and shall not exceed 1.10 per unit for longer than 45 seconds cumulatively per simulated event at each generator bus and generator step-up transformer high-side bus associated with each of the following:

E.B.3.3.1. Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES

E.B.3.3.2. Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES

- E.B.3.3.3.** Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- E.B.4.** Each Planning Coordinator shall participate in and document a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
- E.B.4.1.** Underfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.2.** Underfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.3.** Underfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-1(X) - Attachment 1.
- E.B.4.4.** Overfrequency trip settings of individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.5.** Overfrequency trip settings of generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.6.** Overfrequency trip settings of any facility consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA (gross nameplate rating) that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-1(X) — Attachment 1.
- E.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- E.B.11.** Each Planning Coordinator, in whose area a BES islanding event results in system frequency excursions below the initializing set points of the UFLS program, shall participate in and document a coordinated event assessment with all affected Planning Coordinators to conduct and document an assessment of the

event within one year of event actuation to evaluate: *[VRF: Medium][Time Horizon: Operations Assessment]*

E.B.11.1. The performance of the UFLS equipment,

E.B.11.2 The effectiveness of the UFLS program

E.B.12. Each Planning Coordinator, in whose islanding event assessment (per E.B.11) UFLS program deficiencies are identified, shall participate in and document a coordinated UFLS design assessment of the UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies within two years of event actuation. *[VRF: Medium][Time Horizon: Operations Assessment]*

- M.E.B.1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria, developed as part of the joint regional review with other Planning Coordinators in the WECC Regional Entity area to select portions of the Bulk Electric System that may form islands including how system studies and historical events were considered to develop the criteria per Requirement E.B.1.
- M.E.B.2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of an island(s), from the regional review (per E.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement E.B.2 Parts E.B.2.1 and E.B.2.2.
- M.E.B.3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its adoption of a UFLS program, coordinated across the WECC Regional Entity area, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement E.B.3 Parts E.B.3.1 through E.B.3.3.
- M.E.B.4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its participation in a coordinated UFLS design assessment with the other Planning Coordinators in the WECC Regional Entity area that demonstrates it meets Requirement E.B.4 Parts E.B.4.1 through E.B.4.7.
- M.E.B.11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a coordinated event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement E.B.11.
- M.E.B.12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it participated in a UFLS design assessment per Requirements E.B.12 and E.B.4 if UFLS program deficiencies are identified in E.B.11.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.B.1	N/A	<p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p> <p>OR</p> <p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p>	<p>The Planning Coordinator participated in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria but failed to include the consideration of historical events and system studies, to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas, that may form islands</p>	<p>The Planning Coordinator failed to participate in a joint regional review with the other Planning Coordinators in the WECC Regional Entity area that developed and documented criteria to select portions of the BES, including interconnected portions of the BES in adjacent Planning Coordinator areas that may form islands</p>
E.B.2	N/A	N/A	<p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include one (1) of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p>	<p>The Planning Coordinator identified an island(s) from the regional review to serve as a basis for designing its UFLS program but failed to include all of the parts as specified in Requirement E.B.2, Parts E.B.2.1 or E.B.2.2</p> <p>OR</p>

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>The Planning Coordinator failed to identify any island(s) from the regional review to serve as a basis for designing its UFLS program.</p>
E.B.3	N/A	<p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p>	<p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet two (2) of the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, or E.B.3.3 in simulations of underfrequency conditions</p>	<p>The Planning Coordinator adopted a UFLS program, coordinated across the WECC Regional Entity area that included notification of and a schedule for implementation by UFLS entities within its area, but failed to meet all the performance characteristic in Requirement E.B.3, Parts E.B.3.1, E.B.3.2, and E.B.3.3 in simulations of underfrequency conditions</p> <p>OR</p> <p>The Planning Coordinator failed to adopt a UFLS program, coordinated across the WECC Regional Entity area, including notification of and a schedule for implementation by UFLS entities within its area.</p>
E.B.4	<p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>	<p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>	<p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>	<p>The Planning Coordinator participated in and documented a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island</p>

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>identified in Requirement E.B.2 but the simulation failed to include one (1) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>	<p>identified in Requirement E.B.2 but the simulation failed to include two (2) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>	<p>identified in Requirement E.B.2 but the simulation failed to include three (3) of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p>	<p>identified in Requirement E.B.2 but the simulation failed to include four (4) or more of the items as specified in Requirement E.B.4, Parts E.B.4.1 through E.B.4.7.</p> <p>OR</p> <p>The Planning Coordinator failed to participate in and document a coordinated UFLS assessment with the other Planning Coordinators in the WECC Regional Entity area at least once every five years that determines through dynamic simulation whether the UFLS program design meets the performance characteristics in Requirement E.B.3 for each island identified in Requirement E.B.2</p>
E.B.11	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 14 months but less than or equal to 15 months of actuation.</p>	<p>The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event and evaluated the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2 within a time greater than 15 months of actuation.</p> <p>OR</p>

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
			<p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate one (1) of the parts as specified in Requirement E.B.11, Parts E.B.11.1 or E.B.11.2.</p>	<p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, failed to participate in and document a coordinated event assessment with all Planning Coordinators whose areas or portion of whose areas were also included in the same island event and evaluate the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p> <p>OR</p> <p>The Planning Coordinator, in whose area an islanding event resulting in system frequency excursions below the initializing set points of the UFLS program, participated in and documented a coordinated event assessment with all Planning Coordinators whose areas or portions of whose areas were also included in the same islanding event within one year of event actuation but failed to evaluate all of the parts as specified in Requirement E.B.11, Parts E.B.11.1 and E.B.11.2.</p>
E.B.12	N/A	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design	The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, participated in and documented a coordinated UFLS design

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than two years but less than or equal to 25 months of event actuation.</p>	<p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 25 months but less than or equal to 26 months of event actuation.</p>	<p>assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies in greater than 26 months of event actuation.</p> <p>OR</p> <p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement E.B.11, failed to participate in and document a coordinated UFLS design assessment of the coordinated UFLS program with the other Planning Coordinators in the WECC Regional Entity area to consider the identified deficiencies</p>

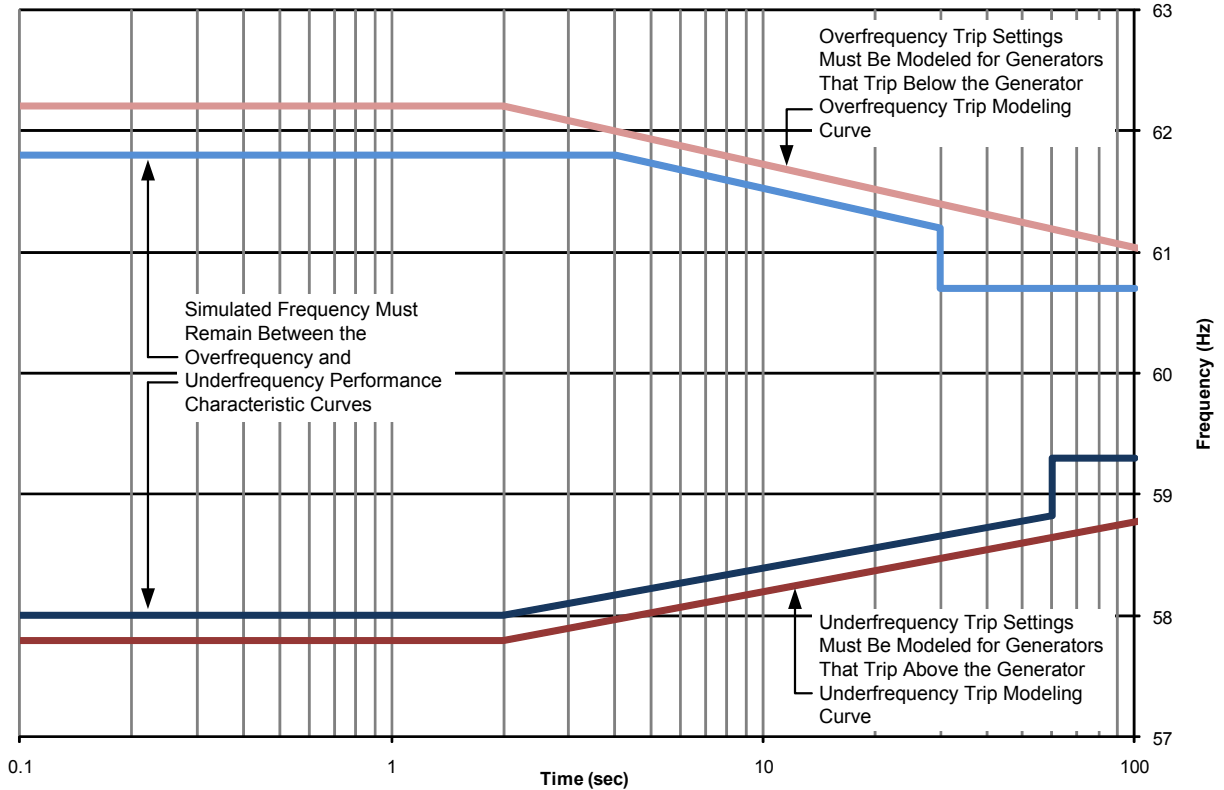
Associated Documents

Version History

Version	Date	Action	Change Tracking
1	May 25, 2010	Completed revision, merging and updating PRC-006-0, PRC-007-0 and PRC-009-0.	
1	November 4, 2010	Adopted by the Board of Trustees	
1	May 7, 2012	FERC Order issued approving PRC-006-1 (approval becomes effective July 10, 2012)	
1	November 9, 2012	FERC Letter Order issued accepting the modification of the VRF in R5 from (Medium to High) and the modification of the VSL language in R8.	
<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

PRC-006-1(X) – Attachment 1

Underfrequency Load Shedding Program Design Performance and Modeling Curves for Requirements R3 Parts 3.1-3.2 and R4 Parts 4.1-4.6

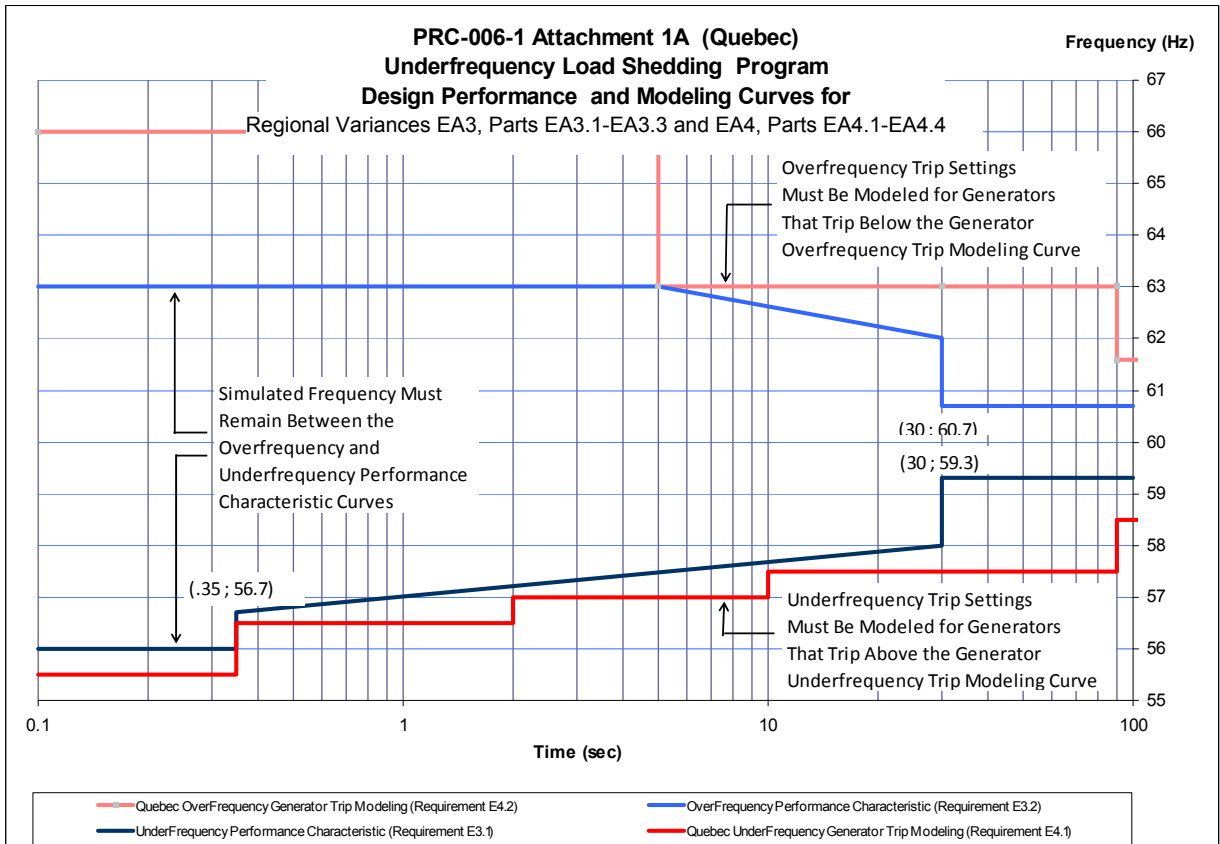


□□□□	Generator Overfrequency Trip Modeling (Requirement R4 Parts 4.4-4.6)
□□□□	Overfrequency Performance Characteristic (Requirement R3 Part 3.2)
□□□□	Underfrequency Performance Characteristic (Requirement R3 Part 3.1)
□□□□	Generator Underfrequency Trip Modeling (Requirement R4 Parts 4.1-4.3)

Curve Definitions

Generator Overfrequency Trip Modeling		Overfrequency Performance Characteristic		
$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 4 \text{ s}$	$4 \text{ s} < t \leq 30 \text{ s}$	$t > 30 \text{ s}$
$f = 62.2 \text{ Hz}$	$f = -0.686\log(t) + 62.41 \text{ Hz}$	$f = 61.8 \text{ Hz}$	$f = -0.686\log(t) + 62.21 \text{ Hz}$	$f = 60.7 \text{ Hz}$

Generator Underfrequency Trip Modeling		Underfrequency Performance Characteristic		
$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 2 \text{ s}$	$2 \text{ s} < t \leq 60 \text{ s}$	$t > 60 \text{ s}$
$f = 57.8 \text{ Hz}$	$f = 0.575\log(t) + 57.63 \text{ Hz}$	$f = 58.0 \text{ Hz}$	$f = 0.575\log(t) + 57.83 \text{ Hz}$	$f = 59.3 \text{ Hz}$



A. Introduction

- 1. Title:** Remedial Action Scheme Review Procedure
- 2. Number:** PRC-012-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
 - 4.1.** Regional Reliability Organization
- 5. Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:
 - R1.1.** Description of the process for submitting a proposed RAS for Regional Reliability Organization review.
 - R1.2.** Requirements to provide data that describes design, operation, and modeling of a RAS.
 - R1.3.** Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
 - R1.4.** Requirements to demonstrate that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
 - R1.5.** Requirements to demonstrate the proposed RAS will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
 - R1.6.** Regional Reliability Organization definition of misoperation.
 - R1.7.** Requirements for analysis and documentation of corrective action plans for all RAS misoperations.
 - R1.8.** Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
 - R1.9.** Determination, as appropriate, of maintenance and testing requirements.
- R2.** The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

C. Measures

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use a RAS shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0(X)_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its RAS review procedure on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

- 2.1. Level 1:** Documentation of the Regional Reliability Organization’s procedure is missing one of the items listed in Reliability Standard PRC-012-0(X)_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization’s procedure is missing two of the items listed in Reliability Standard PRC-012-0(X)_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization’s procedure is missing three of the items listed in Reliability Standard PRC-012-0(X)_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization’s procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0(X)_R1.

E. Regional Differences

- 1.** None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard PRC-012-0(X) — ~~Special Protection System~~ Remedial Action Scheme Review Procedure

A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Review Procedure
2. **Number:** PRC-012-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
 - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a ~~n-SPS RAS~~ shall have a documented Regional Reliability Organization ~~SPSRAS~~ review procedure to ensure that ~~SPSRAS~~s comply with Regional criteria and NERC Reliability Standards. The Regional ~~SPSRAS~~ review procedure shall include:
 - R1.1. Description of the process for submitting a proposed ~~SPSRAS~~ for Regional Reliability Organization review.
 - R1.2. Requirements to provide data that describes design, operation, and modeling of a ~~n-SPSRAS~~.
 - R1.3. Requirements to demonstrate that the ~~SPSRAS~~ shall be designed so that a single ~~SPSRAS~~ component failure, when the ~~SPSRAS~~ was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
 - R1.4. Requirements to demonstrate that the inadvertent operation of a ~~n-SPSRAS~~ shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed, and not exceed TPL-003-0.
 - R1.5. Requirements to demonstrate the proposed ~~SPSRAS~~ will coordinate with other protection and control systems and applicable Regional Reliability Organization Emergency procedures.
 - R1.6. Regional Reliability Organization definition of misoperation.
 - R1.7. Requirements for analysis and documentation of corrective action plans for all ~~SPSRAS~~ misoperations.
 - R1.8. Identification of the Regional Reliability Organization group responsible for the Regional Reliability Organization's review procedure and the process for Regional Reliability Organization approval of the procedure.
 - R1.9. Determination, as appropriate, of maintenance and testing requirements.
- R2. The Regional Reliability Organization shall provide affected Regional Reliability Organizations and NERC with documentation of its ~~SPSRAS~~ review procedure on request (within 30 calendar days).

Standard PRC-012-0(X) — ~~Special Protection System~~ Remedial Action Scheme Review Procedure

C. Measures

- M1.** The Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Provider using or planning to use an ~~SPS RAS~~ shall have a documented Regional review procedure as defined in Reliability Standard PRC-012-0(X)_R1.
- M2.** The Regional Reliability Organization shall have evidence it provided affected Regional Reliability Organizations and NERC with documentation of its ~~SPSRAS~~ review procedure on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

- 2.1. Level 1:** Documentation of the Regional Reliability Organization's procedure is missing one of the items listed in Reliability Standard PRC-012-0(X)_R1.
- 2.2. Level 2:** Documentation of the Regional Reliability Organization's procedure is missing two of the items listed in Reliability Standard PRC-012-0(X)_R1.
- 2.3. Level 3:** Documentation of the Regional Reliability Organization's procedure is missing three of the items listed in Reliability Standard PRC-012-0(X)_R1.
- 2.4. Level 4:** Documentation of the Regional Reliability Organization's procedure was not provided or is missing four or more of the items listed in Reliability Standard PRC-012-0(X)_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
<u>0(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Standard PRC-012-0(X) — ~~Special Protection System~~ Remedial Action Scheme Review Procedure

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A. Introduction

1. **Title:** Remedial Action Scheme Database.
2. **Number:** PRC-013-0(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
 - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a RAS installed shall maintain a RAS database. The database shall include the following types of information:
 - R1.1. Design Objectives — Contingencies and system conditions for which the RAS was designed,
 - R1.2. Operation — The actions taken by the RAS in response to Disturbance conditions, and
 - R1.3. Modeling — Information on detection logic or relay settings that control operation of the RAS.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a RAS installed, shall have a RAS database as defined in PRC-013-0(X)_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
 - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
 - 1.3. **Data Retention**

None specified.
 - 1.4. **Additional Compliance Information**

None.

2. Levels of Non-Compliance

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0(X)_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-0(X)_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0(X)_R1.

E. Regional Differences

- 1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Dave	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Database.
2. **Number:** PRC-013-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPSs)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
4. **Applicability:**
 - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Provider with a ~~an SPS RAS~~ installed shall maintain a ~~an SPS RAS~~ database. The database shall include the following types of information:
 - R1.1. Design Objectives — Contingencies and system conditions for which the ~~SPSRAS~~ was designed,
 - R1.2. Operation — The actions taken by the ~~SPSRAS~~ in response to Disturbance conditions, and
 - R1.3. Modeling — Information on detection logic or relay settings that control operation of the ~~SPSRAS~~.
- R2. The Regional Reliability Organization shall provide to affected Regional Reliability Organization(s) and NERC documentation of its database or the information therein on request (within 30 calendar days).

C. Measures

- M1. The Regional Reliability Organization that has a Transmission Owner, Generator Owner, or Distribution Providers with a ~~an SPS RAS~~ installed, shall have a ~~an SPS RAS~~ database as defined in PRC-013-0(X)_R1 of this Reliability Standard.
- M2. The Regional Reliability Organization shall have evidence it provided documentation of its database or the information therein, to affected Regional Reliability Organization(s) and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: NERC.
 - 1.2. **Compliance Monitoring Period and Reset Timeframe**

On request (within 30 calendar days.)
 - 1.3. **Data Retention**

None specified.
 - 1.4. **Additional Compliance Information**

None.

2. Levels of Non-Compliance

- 2.1. Level 1:** The Regional Reliability Organization’s database is missing one of the items listed in Reliability Standard PRC-013-0(X)_R1.
- 2.2. Level 2:** The Regional Reliability Organization’s database is missing two of the items listed in Reliability Standard PRC-013-0(X)9_R1.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** The Regional Reliability Organization’s database was not provided or is missing all of the elements listed in Reliability Standard PRC-013-0(X)_R1.

E. Regional Differences

- 1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Dave	New
<u>0(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

- 1. Title:** Remedial Action Scheme Assessment
- 2. Number:** PRC-014-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
 - 4.1.** Regional Reliability Organization
- 5. Effective Date:** April 1, 2005

B. Requirements

- R1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all RAS installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3.** The documentation of the Regional Reliability Organization's RAS assessment shall include the following elements:
 - R3.1.** Identification of group conducting the assessment and the date the assessment was performed.
 - R3.2.** Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
 - R3.3.** Identification of RAS that were found not to comply with NERC standards and Regional Reliability Organization criteria.
 - R3.4.** Discussion of any coordination problems found between a RAS and other protection and control systems.
 - R3.5.** Provide corrective action plans for non-compliant RAS.

C. Measures

- M1.** The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all RAS installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2.** The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3.** The Regional Reliability Organization's documentation of the RAS assessment shall include all elements as defined in Reliability Standard PRC-014-0(X)_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The summary (or detailed) Regional RAS assessment is missing one of the items listed in Reliability Standard PRC-014-0(X)_R3.

2.2. Level 2: The summary (or detailed) Regional RAS assessment is missing two of the items listed in Reliability Standard PRC-014-0(X)_3.

2.3. Level 3: The summary (or detailed) Regional RAS assessment is missing three of the items listed in Reliability Standard PRC-014-0(X)_R3.

2.4. Level 4: The summary (or detailed) Regional RAS assessment is missing more than three of the items listed in Reliability Standard PRC-014-0(X)_R3 or was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Assessment
2. **Number:** PRC-014-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
 - 4.1. Regional Reliability Organization
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all ~~SPSRAS~~s installed in its Region at least once every five years for compliance with NERC Reliability Standards and Regional criteria.
- R2. The Regional Reliability Organization shall provide either a summary report or a detailed report of its assessment of the operation, coordination, and effectiveness of all ~~SPSRAS~~s installed in its Region to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- R3. The documentation of the Regional Reliability Organization's ~~SPSRAS~~ assessment shall include the following elements:
 - R3.1. Identification of group conducting the assessment and the date the assessment was performed.
 - R3.2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
 - R3.3. Identification of ~~SPSRAS~~s that were found not to comply with NERC standards and Regional Reliability Organization criteria.
 - R3.4. Discussion of any coordination problems found between a ~~SPSRAS~~ and other protection and control systems.
 - R3.5. Provide corrective action plans for non-compliant ~~SPSRAS~~s.

C. Measures

- M1. The Regional Reliability Organization shall assess the operation, coordination, and effectiveness of all ~~SPSRAS~~s installed in its Region at least once every five years for compliance with NERC standards and Regional criteria.
- M2. The Regional Reliability Organization shall provide either a summary report or a detailed report of this assessment to affected Regional Reliability Organizations or NERC on request (within 30 calendar days).
- M3. The Regional Reliability Organization's documentation of the ~~SPSRAS~~ assessment shall include all elements as defined in Reliability Standard PRC-014-0(X)_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: NERC.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: The summary (or detailed) Regional [SPSRAS](#) assessment is missing one of the items listed in Reliability Standard PRC-014-0(X)_R3.

2.2. Level 2: The summary (or detailed) Regional [SPSRAS](#) assessment is missing two of the items listed in Reliability Standard PRC-014-0(X)_3.

2.3. Level 3: The summary (or detailed) Regional [SPSRAS](#) assessment is missing three of the items listed in Reliability Standard PRC-014-0(X)_R3.

2.4. Level 4: The summary (or detailed) Regional [SPSRAS](#) assessment is missing more than three of the items listed in Reliability Standard PRC-014-0(X)_R3 or was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

- 1. Title:** Remedial Action Scheme Data and Documentation
- 2. Number:** PRC-015-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
 - 4.1.** Transmission Owner that owns a RAS
 - 4.2.** Generator Owner that owns a RAS
 - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

B. Requirements

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall maintain a list of and provide data for existing and proposed RAS as specified in Reliability Standard PRC-013-0(X)_R1.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)_R1 prior to being placed in service.
- R3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of RAS data and the results of Studies that show compliance of new or functionally modified RAS with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it maintains a list of and provides data for existing and proposed RAS as defined in Reliability Standard PRC-013-0(X)_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it reviewed new or functionally modified RAS in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)_R1 prior to being placed in service.
- M3.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of RAS data and the results of studies that show compliance of new or functionally modified RAS with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: RAS owners provided RAS data, but was incomplete according to the Regional Reliability Organization RAS database requirements.

2.2. Level 2: RAS owners provided results of studies that show compliance of new or functionally modified RAS with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: No RAS data was provided in accordance with Regional Reliability Organization RAS database requirements for Standard PRC-012-0(X)_R1, or the results of studies that show compliance of new or functionally modified RAS with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard PRC-015-0(X) — ~~Special Protection System~~ Remedial Action Scheme Data and Documentation

A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Data and Documentation
2. **Number:** PRC-015-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
 - 4.1. Transmission Owner that owns an ~~SPS~~ RAS
 - 4.2. Generator Owner that owns an ~~SPS~~ RAS
 - 4.3. Distribution Provider that owns an ~~SPS~~ RAS
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall maintain a list of and provide data for existing and proposed ~~SPS~~RASs as specified in Reliability Standard PRC-013-0(X)_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have evidence it reviewed new or functionally modified ~~SPS~~RASs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)_R1 prior to being placed in service.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall provide documentation of ~~SPS~~RAS data and the results of Studies that show compliance of new or functionally modified ~~SPS~~RASs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall have evidence it maintains a list of and provides data for existing and proposed ~~SPS~~RASs as defined in Reliability Standard PRC-013-0(X)_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall have evidence it reviewed new or functionally modified ~~SPS~~RASs in accordance with the Regional Reliability Organization's procedures as defined in Reliability Standard PRC-012-0(X)_R1 prior to being placed in service.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~SPS~~RAS shall have evidence it provided documentation of ~~SPS~~RAS data and the results of studies that show compliance of new or functionally modified ~~SPS~~RASs with NERC standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. **Compliance Monitoring Process**

Standard PRC-015-0(X) — ~~Special Protection System~~ Remedial Action Scheme Data and Documentation

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

On request (within 30 calendar days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: [SPSRAS](#) owners provided [SPSRAS](#) data, but was incomplete according to the Regional Reliability Organization [SPSRAS](#) database requirements.

2.2. Level 2: [SPSRAS](#) owners provided results of studies that show compliance of new or functionally modified [SPSRASs](#) with the NERC Planning Standards and Regional Reliability Organization criteria, but were incomplete according to the Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)_R1.

2.3. Level 3: Not applicable.

2.4. Level 4: No [SPSRAS](#) data was provided in accordance with Regional Reliability Organization [SPSRAS](#) database requirements for Standard PRC-012-0(X)_R1, or the results of studies that show compliance of new or functionally modified [SPSRASs](#) with the NERC Reliability Standards and Regional Reliability Organization criteria were not provided in accordance with Regional Reliability Organization procedures for Reliability Standard PRC-012-0(X)_R1.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title: Remedial Action Scheme Misoperations**
2. **Number:** PRC-016-0.1(X)
3. **Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
 - 4.1. Transmission Owner that owns a RAS.
 - 4.2. Generator Owner that owns a RAS.
 - 4.3. Distribution Provider that owns a RAS.
5. **Effective Date:** May 13, 2009

B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall analyze its RAS operations and maintain a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it analyzed RAS operations and maintained a record of all misoperations in accordance with the Regional RAS review procedure specified in Reliability Standard PRC-012-0(X)_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it took corrective actions to avoid future misoperations.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Compliance Monitor: Regional Reliability Organization.

Standard PRC-016-0.1(X) — Remedial Action Scheme Misoperations

1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of RAS misoperations is complete but documentation of corrective actions taken for all identified RAS misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for RAS misoperations is complete but documentation of RAS misoperations is incomplete.

2.3. Level 3: Documentation of RAS misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of RAS misoperations or corrective actions.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	July 3, 2007	Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.”	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised
0.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard PRC-016-0.1(X) — ~~Special Protection System~~ Remedial Action Scheme Misoperations

A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Misoperations
2. **Number:** PRC-016-0.1(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
 - 4.1. Transmission Owner that owns a ~~an SPS~~ RAS.
 - 4.2. Generator Owner that owns a ~~an SPS~~ RAS.
 - 4.3. Distribution Provider that owns a ~~an SPS~~ RAS.
5. **Effective Date:** May 13, 2009

B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an~~ SPSRAS shall analyze its SPSRAS operations and maintain a record of all misoperations in accordance with the Regional SPSRAS review procedure specified in Reliability Standard PRC-012-0(X)_R1.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an~~ SPSRAS shall take corrective actions to avoid future misoperations.
- R3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an~~ SPSRAS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request (within 90 calendar days).

C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an~~ SPSRAS shall have evidence it analyzed SPSRAS operations and maintained a record of all misoperations in accordance with the Regional SPSRAS review procedure specified in Reliability Standard PRC-012-0(X)_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an~~ SPSRAS shall have evidence it took corrective actions to avoid future misoperations.
- M3. The Transmission Owner, Generator Owner, and Distribution Provider that owns a ~~an~~ SPSRAS shall have evidence it provided documentation of the misoperation analyses and the corrective action plans to the affected Regional Reliability Organization and NERC on request (within 90 calendar days).

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Standard PRC-016-0.1(X) — ~~Special Protection System~~ Remedial Action Scheme Misoperations

Compliance Monitor: Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

On request [within 90 calendar days of the incident or on request (within 30 calendar days) if requested more than 90 calendar days after the incident.]

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of [SPSRAS](#) misoperations is complete but documentation of corrective actions taken for all identified [SPSRAS](#) misoperations is incomplete.

2.2. Level 2: Documentation of corrective actions taken for [SPSRAS](#) misoperations is complete but documentation of [SPSRAS](#) misoperations is incomplete.

2.3. Level 3: Documentation of [SPSRAS](#) misoperations and corrective actions is incomplete.

2.4. Level 4: No documentation of [SPSRAS](#) misoperations or corrective actions.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	July 3, 2007	Change reference in Measure 1 from “PRC-016-0_R1” to “PRC-012-1_R1.”	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised
0.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection

Standard PRC-016-0.1(X) — ~~Special Protection System~~ Remedial Action Scheme
Misoperations

			<u>System and SPS with Remedial Action Scheme and RAS</u>
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A. Introduction

- 1. Title:** Remedial Action Scheme Maintenance and Testing
- 2. Number:** PRC-017-0(X)
- 3. Purpose:** To ensure that all Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
- 4. Applicability:**
 - 4.1.** Transmission Owner that owns a RAS
 - 4.2.** Generator Owner that owns a RAS
 - 4.3.** Distribution Provider that owns a RAS
- 5. Effective Date:** April 1, 2005

B. Requirements

- R1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
 - R1.1.** RAS identification shall include but is not limited to:
 - R1.1.1.** Relays.
 - R1.1.2.** Instrument transformers.
 - R1.1.3.** Communications systems, where appropriate.
 - R1.1.4.** Batteries.
 - R1.2.** Documentation of maintenance and testing intervals and their basis.
 - R1.3.** Summary of testing procedure.
 - R1.4.** Schedule for system testing.
 - R1.5.** Schedule for system maintenance.
 - R1.6.** Date last tested/maintained.
- R2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

- M1.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0(X)_R1.
- M2.** The Transmission Owner, Generator Owner, and Distribution Provider that owns a RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Timeframe:

On request (30 calendar days.)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard PRC-017-0(X) — ~~Special Protection System~~ Remedial Action Scheme Maintenance and Testing

A. Introduction

1. **Title:** ~~Special Protection System~~ Remedial Action Scheme Maintenance and Testing
2. **Number:** PRC-017-0(X)
3. **Purpose:** To ensure that all ~~Special Protection Systems (SPS)~~ Remedial Action Schemes (RAS) are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.
4. **Applicability:**
 - 4.1. Transmission Owner that owns an ~~SPS~~ RAS
 - 4.2. Generator Owner that owns an ~~SPS~~ RAS
 - 4.3. Distribution Provider that owns an ~~SPS~~ RAS
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have a system maintenance and testing program(s) in place. The program(s) shall include:
 - R1.1. ~~SPS~~RAS identification shall include but is not limited to:
 - R1.1.1. Relays.
 - R1.1.2. Instrument transformers.
 - R1.1.3. Communications systems, where appropriate.
 - R1.1.4. Batteries.
 - R1.2. Documentation of maintenance and testing intervals and their basis.
 - R1.3. Summary of testing procedure.
 - R1.4. Schedule for system testing.
 - R1.5. Schedule for system maintenance.
 - R1.6. Date last tested/maintained.
- R2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall provide documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

C. Measures

- M1. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have a system maintenance and testing program(s) in place that includes all items in Reliability Standard PRC-017-0(X)_R1.
- M2. The Transmission Owner, Generator Owner, and Distribution Provider that owns an ~~SPS~~ RAS shall have evidence it provided documentation of the program and its implementation to the appropriate Regional Reliability Organizations and NERC on request (within 30 calendar days).

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization. Each Region shall report compliance and violations to NERC via the NERC Compliance Reporting process.

Timeframe:

On request (30 calendar days.)

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitor: Regional Reliability Organization.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Documentation of the maintenance and testing program was incomplete, but records indicate implementation was on schedule.

2.2. Level 2: Complete documentation of the maintenance and testing program was provided, but records indicate that implementation was not on schedule.

2.3. Level 3: Documentation of the maintenance and testing program was incomplete, and records indicate implementation was not on schedule.

2.4. Level 4: Documentation of the maintenance and testing program, or its implementation, was not provided.

E. Regional Differences

- None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-1(X)
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
 - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** May 1, 2006

B. Requirements

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
 - R1.1. Owner and operator of the UVLS program.
 - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
 - R1.3. Corresponding voltage set points and overall scheme clearing times.
 - R1.4. Time delay from initiation to trip signal.
 - R1.5. Breaker operating times.
 - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

C. Measures

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

NERC
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
 - 1.3. **Data Retention**

Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS database annually.

2.2. Level 2: UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. Level 3: Not applicable.

2.4. Level 4: Did not provide information from its UVLS program database.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	<ol style="list-style-type: none"> 1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—).” 3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 4. Added or removed “periods” where appropriate. 5. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/06
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Database
2. **Number:** PRC-020-1(X)
3. **Purpose:** Ensure that a regional database is maintained for Under-Voltage Load Shedding (UVLS) programs implemented by entities within the Region to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES). Ensure the UVLS database is available for Regional studies and for dynamic studies and simulations of the BES.
4. **Applicability**
 - 4.1. Regional Reliability Organization with entities that own or operate a UVLS program.
5. **Effective Date:** May 1, 2006

B. Requirements

- R1. The Regional Reliability Organization shall establish, maintain and annually update a database for UVLS programs implemented by entities within the region to mitigate the risk of voltage collapse or voltage instability in the BES. This database shall include the following items:
 - R1.1. Owner and operator of the UVLS program.
 - R1.2. Size and location of customer load, or percent of connected load, to be interrupted.
 - R1.3. Corresponding voltage set points and overall scheme clearing times.
 - R1.4. Time delay from initiation to trip signal.
 - R1.5. Breaker operating times.
 - R1.6. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and [Special Protection System Remedial Action Schemes](#).
- R2. The Regional Reliability Organization shall provide the information in its UVLS database to the Planning Authority, the Transmission Planner, or other Regional Reliability Organizations and to NERC within 30 calendar days of a request.

C. Measures

- M1. The Regional Reliability Organization shall have evidence that it established and annually updated its UVLS database to include all elements in Requirement 1.1 through 1.6.
- M2. The Regional Reliability Organization shall have evidence that it provided the information in its UVLS database to the requesting entities and to NERC in accordance with Requirement 2.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

NERC
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
 - 1.3. **Data Retention**

Standard PRC-020-1(X) — Under-Voltage Load Shedding Program Database

The Regional Reliability Organization shall retain the current and prior annual updated database. The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

The Regional Reliability Organization shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. **Level 1:** Did not update its UVLS database annually.

2.2. **Level 2:** UVLS program database information provided, but did not include all of the items identified in R1.1 through R1.6.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** Did not provide information from its UVLS program database.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	<ol style="list-style-type: none"> 1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash” (—).” 3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 4. Added or removed “periods” where appropriate. 5. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/06
<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Data
2. **Number:** PRC-021-1(X)
3. **Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
 - 4.1. Transmission Owner that owns a UVLS program.
 - 4.2. Distribution Provider that owns a UVLS program.
5. **Effective Date:** August 1, 2006

B. Requirements

- R1. Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
 - R1.1. Size and location of customer load, or percent of connected load, to be interrupted.
 - R1.2. Corresponding voltage set points and overall scheme clearing times.
 - R1.3. Time delay from initiation to trip signal.
 - R1.4. Breaker operating times.
 - R1.5. Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and Remedial Action Schemes.
- R2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

C. Measures

- M1. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2. Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**

One calendar year.
 - 1.3. **Data Retention**

Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS data annually.

2.2. Level 2: UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

2.3. Level 3: UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

2.4. Level 4: Did not provide any UVLS data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	<ol style="list-style-type: none"> 1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Added heading above table “Future Development Plan.” 4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 5. Added or removed “periods” where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

- 1. Title:** Under-Voltage Load Shedding Program Data
- 2. Number:** PRC-021-1(X)
- 3. Purpose:** Ensure data is provided to support the Regional database maintained for Under-Voltage Load Shedding (UVLS) programs that were implemented to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
- 4. Applicability**
 - 4.1.** Transmission Owner that owns a UVLS program.
 - 4.2.** Distribution Provider that owns a UVLS program.
- 5. Effective Date:** August 1, 2006

B. Requirements

- R1.** Each Transmission Owner and Distribution Provider that owns a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall annually update its UVLS data to support the Regional UVLS program database. The following data shall be provided to the Regional Reliability Organization for each installed UVLS system:
 - R1.1.** Size and location of customer load, or percent of connected load, to be interrupted.
 - R1.2.** Corresponding voltage set points and overall scheme clearing times.
 - R1.3.** Time delay from initiation to trip signal.
 - R1.4.** Breaker operating times.
 - R1.5.** Any other schemes that are part of or impact the UVLS programs such as related generation protection, islanding schemes, automatic load restoration schemes, UFLS and [Special Protection System Remedial Action Schemes](#).
- R2.** Each Transmission Owner and Distribution Provider that owns a UVLS program shall provide its UVLS program data to the Regional Reliability Organization within 30 calendar days of a request.

C. Measures

- M1.** Each Transmission Owner and Distribution Provider that owns a UVLS program shall have documentation that its UVLS data was updated annually and includes all items specified in Requirement 1.1 through 1.5.
- M2.** Each Transmission Owner and Distribution Provider that owns a UVLS program shall have evidence it provided the Regional Reliability Organization with its UVLS program data within 30 calendar days of a request.

D. Compliance

- 1. Compliance Monitoring Process**
 - 1.1. Compliance Monitoring Responsibility**

Regional Reliability Organization.
 - 1.2. Compliance Monitoring Period and Reset Time Frame**

One calendar year.
 - 1.3. Data Retention**

Standard PRC-021-1(X) — Under-Voltage Load Shedding Program Data

Each Transmission Owner and Distribution Provider that owns a UVLS program shall retain a copy of the data submitted over the past two years.

The Compliance Monitor shall retain all audit data for three years.

1.4. Additional Compliance Information

Transmission Owner and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Did not update its UVLS data annually.

2.2. Level 2: UVLS data was provided, but did not address one of the items identified in R1.1 through R1.5.

2.3. Level 3: UVLS data was provided, but did not address two or more of the items identified in R1.1 through R1.5.

2.4. Level 4: Did not provide any UVLS data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	12/01/05	<ol style="list-style-type: none"> 1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Added heading above table “Future Development Plan.” 4. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 5. Added or removed “periods” where appropriate. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

1. Title: Transmission Relay Loadability

2. Number: PRC-023-2(X)

3. Purpose: Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. Applicability

4.1. Functional Entity

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinators

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. Effective Dates

The effective dates of the requirements in the PRC-023-2(X) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

Standard PRC-023-2(X) — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption
	<ul style="list-style-type: none"> For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability 	First day of the first calendar quarter 12 months after applicable regulatory approvals	First day of the first calendar quarter 12 months after Board of Trustees adoption
	<ul style="list-style-type: none"> For supervisory elements as described in PRC-023-2(X) - Attachment A, Section 1.6 	First day of the first calendar quarter 24 months after applicable regulatory approvals	First day of the first calendar quarter 24 months after Board of Trustees adoption
	<ul style="list-style-type: none"> For switch-on-to-fault schemes as described in PRC-023-2(X) - Attachment A, Section 1.3 	Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2(X) or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2(X) or July 1, 2011 ¹
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on

¹ July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

Standard PRC-023-2(X) — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Standard PRC-023-2(X) — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5	First day of the first calendar quarter 18 months after applicable regulatory approvals	First day of the first calendar quarter 18 months after Board of Trustees adoption

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating² of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
 - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
 - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
 - 115% of the highest emergency rating of the series capacitor.
 - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

² When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
 - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
 - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability³.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
 - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
 - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature⁴.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
 - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
 - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

³ As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

⁴ IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(X) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	<p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p>
R2	N/A	N/A	N/A	<p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>
R3	N/A	N/A	N/A	<p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>

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Requirement	Lower	Moderate	High	Severe
				The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments.	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments.	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within

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Requirement	Lower	Moderate	High	Severe
		<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p>	<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p>	<p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p>

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Requirement	Lower	Moderate	High	Severe
				<p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>

E. Regional Differences

None

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
2(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

PRC-023 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
 - 1.1. Phase distance.
 - 1.2. Out-of-step tripping.
 - 1.3. Switch-on-to-fault.
 - 1.4. Overcurrent relays.
 - 1.5. Communications aided protection schemes including but not limited to:
 - 1.5.1 Permissive overreach transfer trip (POTT).
 - 1.5.2 Permissive under-reach transfer trip (PUTT).
 - 1.5.3 Directional comparison blocking (DCB).
 - 1.5.4 Directional comparison unblocking (DCUB).
 - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
 - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
 - Overcurrent elements that are only enabled during loss of potential conditions.
 - Elements that are only enabled during a loss of communications except as noted in section 1.6
 - 2.2. Protection systems intended for the detection of ground fault conditions.
 - 2.3. Protection systems intended for protection during stable power swings.
 - 2.4. Generator protection relays that are susceptible to load.
 - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
 - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
 - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
 - 2.8. Relay elements associated with dc lines.
 - 2.9. Relay elements associated with dc converter transformers.

PRC-023 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses⁵ performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
 - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
 - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
 - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

⁵ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
 - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
 - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. Title: Transmission Relay Loadability

2. Number: PRC-023-2(X)

3. Purpose: Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. Applicability

4.1. Functional Entity

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2(X) - Attachment A, applied to circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinators

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. Effective Dates

The effective dates of the requirements in the PRC-023-2(X) standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:

Standard PRC-023-2(X) — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption
	<ul style="list-style-type: none"> For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability 	First day of the first calendar quarter 12 months after applicable regulatory approvals	First day of the first calendar quarter 12 months after Board of Trustees adoption
	<ul style="list-style-type: none"> For supervisory elements as described in PRC-023-2(X) - Attachment A, Section 1.6 	First day of the first calendar quarter 24 months after applicable regulatory approvals	First day of the first calendar quarter 24 months after Board of Trustees adoption
	<ul style="list-style-type: none"> For switch-on-to-fault schemes as described in PRC-023-2(X) - Attachment A, Section 1.3 	Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2(X) or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2(X) or July 1, 2011 ¹
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on

¹ July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.

Standard PRC-023-2(X) — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption
	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2(X) per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Standard PRC-023-2(X) — Transmission Relay Loadability

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5	First day of the first calendar quarter 18 months after applicable regulatory approvals	First day of the first calendar quarter 18 months after Board of Trustees adoption

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating² of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
 - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
 - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
 - 115% of the highest emergency rating of the series capacitor.
 - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.
7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

² When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
 - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
 - 115% of the highest operator established emergency transformer rating
- 10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability³.
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
 - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
 - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature⁴.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
 - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
 - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

³ As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

⁴ IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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- c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.
- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-2(X) per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

If a Transmission Owner, Generator Owner, Distribution Provider or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Monitor shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	<p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p>
R2	N/A	N/A	N/A	<p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>
R3	N/A	N/A	N/A	<p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p> <p>OR</p>

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Requirement	Lower	Moderate	High	Severe
				The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments.	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments.	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within

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Requirement	Lower	Moderate	High	Severe
		<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated. (part 6.2)</p>	<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p>	<p>Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission</p>

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Requirement	Lower	Moderate	High	Severe
				<p>Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>

E. Regional Differences

None

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
<u>2(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

PRC-023 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
 - 1.1. Phase distance.
 - 1.2. Out-of-step tripping.
 - 1.3. Switch-on-to-fault.
 - 1.4. Overcurrent relays.
 - 1.5. Communications aided protection schemes including but not limited to:
 - 1.5.1 Permissive overreach transfer trip (POTT).
 - 1.5.2 Permissive under-reach transfer trip (PUTT).
 - 1.5.3 Directional comparison blocking (DCB).
 - 1.5.4 Directional comparison unblocking (DCUB).
 - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
 - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
 - Overcurrent elements that are only enabled during loss of potential conditions.
 - Elements that are only enabled during a loss of communications except as noted in section 1.6
 - 2.2. Protection systems intended for the detection of ground fault conditions.
 - 2.3. Protection systems intended for protection during stable power swings.
 - 2.4. Generator protection relays that are susceptible to load.
 - 2.5. Relay elements used only for ~~Special Protection System~~ Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
 - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
 - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
 - 2.8. Relay elements associated with dc lines.
 - 2.9. Relay elements associated with dc converter transformers.

PRC-023 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses⁵ performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
 - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
 - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
 - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

⁵ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
 - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
 - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-3(X)
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
 - 4.1. **Functional Entity:**
 - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
 - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
 - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
 - 4.1.4 Planning Coordinator
 - 4.2. **Circuits:**
 - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
 - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
 - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
 - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.2 **Circuits Subject to Requirement R6:**
 - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

Criteria:

- 1.** Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
- 2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating¹ of a circuit (expressed in amperes).
- 3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
 - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
 - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
- 4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
 - 115% of the highest emergency rating of the series capacitor.
 - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
- 5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
- 6.** Not used.

¹ When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
 - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
 - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability².
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
 - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
 - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature³.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
 - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
 - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
 - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

² As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

³ IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3(X) per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3(X), Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	<p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p>
R2	N/A	N/A	N/A	<p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>
R3	N/A	N/A	N/A	<p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>

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Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

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Requirement	Lower	Moderate	High	Severe
		<p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p>	<p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p>	<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p>

Standard PRC-023-3(X) — Transmission Relay Loadability

Requirement	Lower	Moderate	High	Severe
		<p>the list was established or updated. (part 6.2)</p>		<p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Standard PRC-023-3(X) — Transmission Relay Loadability

Version	Date	Action	Change Tracking
3(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

PRC-023-3(X) — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
 - 1.1. Phase distance.
 - 1.2. Out-of-step tripping.
 - 1.3. Switch-on-to-fault.
 - 1.4. Overcurrent relays.
 - 1.5. Communications aided protection schemes including but not limited to:
 - 1.5.1 Permissive overreach transfer trip (POTT).
 - 1.5.2 Permissive under-reach transfer trip (PUTT).
 - 1.5.3 Directional comparison blocking (DCB).
 - 1.5.4 Directional comparison unblocking (DCUB).
 - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
 - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
 - Overcurrent elements that are only enabled during loss of potential conditions.
 - Elements that are only enabled during a loss of communications except as noted in section 1.6.
 - 2.2. Protection systems intended for the detection of ground fault conditions.
 - 2.3. Protection systems intended for protection during stable power swings.
 - 2.4. Not used.
 - 2.5. Relay elements used only for Remedial Action Schemes applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
 - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
 - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
 - 2.8. Relay elements associated with dc lines.
 - 2.9. Relay elements associated with dc converter transformers.

PRC-023-3(X) — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses⁴ performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
 - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
 - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
 - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

⁴ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

Standard PRC-023-3(X) — Transmission Relay Loadability

- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
 - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
 - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** Transmission Relay Loadability
2. **Number:** PRC-023-3(X)
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
 - 4.1. **Functional Entity:**
 - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
 - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
 - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3(X) - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
 - 4.1.4 Planning Coordinator
 - 4.2. **Circuits:**
 - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
 - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
 - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
 - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.2 **Circuits Subject to Requirement R6:**
 - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating¹ of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
 - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
 - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
 - 115% of the highest emergency rating of the series capacitor.
 - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

¹ When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
 - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
 - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability².
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
 - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
 - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature³.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
 - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
 - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
 - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

² As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

³ IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3(X) per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3(X), Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3(X), Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	<p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p>
R2	N/A	N/A	N/A	<p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>
R3	N/A	N/A	N/A	<p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>

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Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

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Requirement	Lower	Moderate	High	Severe
		<p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after</p>	<p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p>	<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p>

Standard PRC-023-3(X) — Transmission Relay Loadability

Requirement	Lower	Moderate	High	Severe
		<p>the list was established or updated. (part 6.2)</p>		<p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

Standard PRC-023-3(X) — Transmission Relay Loadability

Version	Date	Action	Change Tracking
<u>3(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

PRC-023-3(X) — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
 - 1.1. Phase distance.
 - 1.2. Out-of-step tripping.
 - 1.3. Switch-on-to-fault.
 - 1.4. Overcurrent relays.
 - 1.5. Communications aided protection schemes including but not limited to:
 - 1.5.1 Permissive overreach transfer trip (POTT).
 - 1.5.2 Permissive under-reach transfer trip (PUTT).
 - 1.5.3 Directional comparison blocking (DCB).
 - 1.5.4 Directional comparison unblocking (DCUB).
 - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
 - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
 - Overcurrent elements that are only enabled during loss of potential conditions.
 - Elements that are only enabled during a loss of communications except as noted in section 1.6.
 - 2.2. Protection systems intended for the detection of ground fault conditions.
 - 2.3. Protection systems intended for protection during stable power swings.
 - 2.4. Not used.
 - 2.5. Relay elements used only for [Special Protection System Remedial Action Schemes](#) applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
 - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
 - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
 - 2.8. Relay elements associated with dc lines.
 - 2.9. Relay elements associated with dc converter transformers.

PRC-023-3(X) — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses⁴ performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
 - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
 - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
 - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

⁴ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

Standard PRC-023-3(X) — Transmission Relay Loadability

- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
 - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
 - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
- e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
 - 4.1. Generator Owner
5. **Effective Date:**
 - 5.1. In those jurisdictions where regulatory approval is required:
 - 5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.2. In those jurisdictions where regulatory approval is not required:
 - 5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- 5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
- 5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

- R1.** Each Generator Owner that has generator frequency protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection²) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip in accordance with a Remedial Action Scheme (RAS).
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

¹ Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

² For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation³ that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice.
[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
 - Repair of the equipment causing the limitation that removes the limitation.
 - Replacement of the equipment causing the limitation with equipment that removes the limitation.
 - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

C. Measures

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement

³ Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer’s advice.

- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

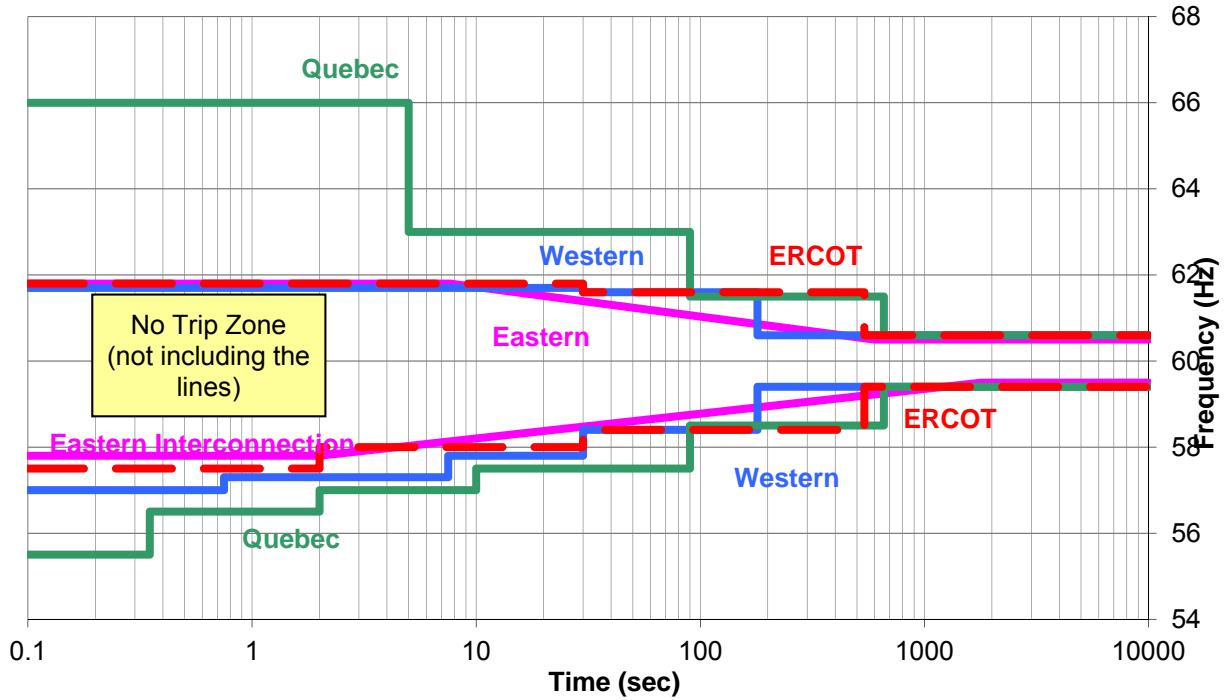
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

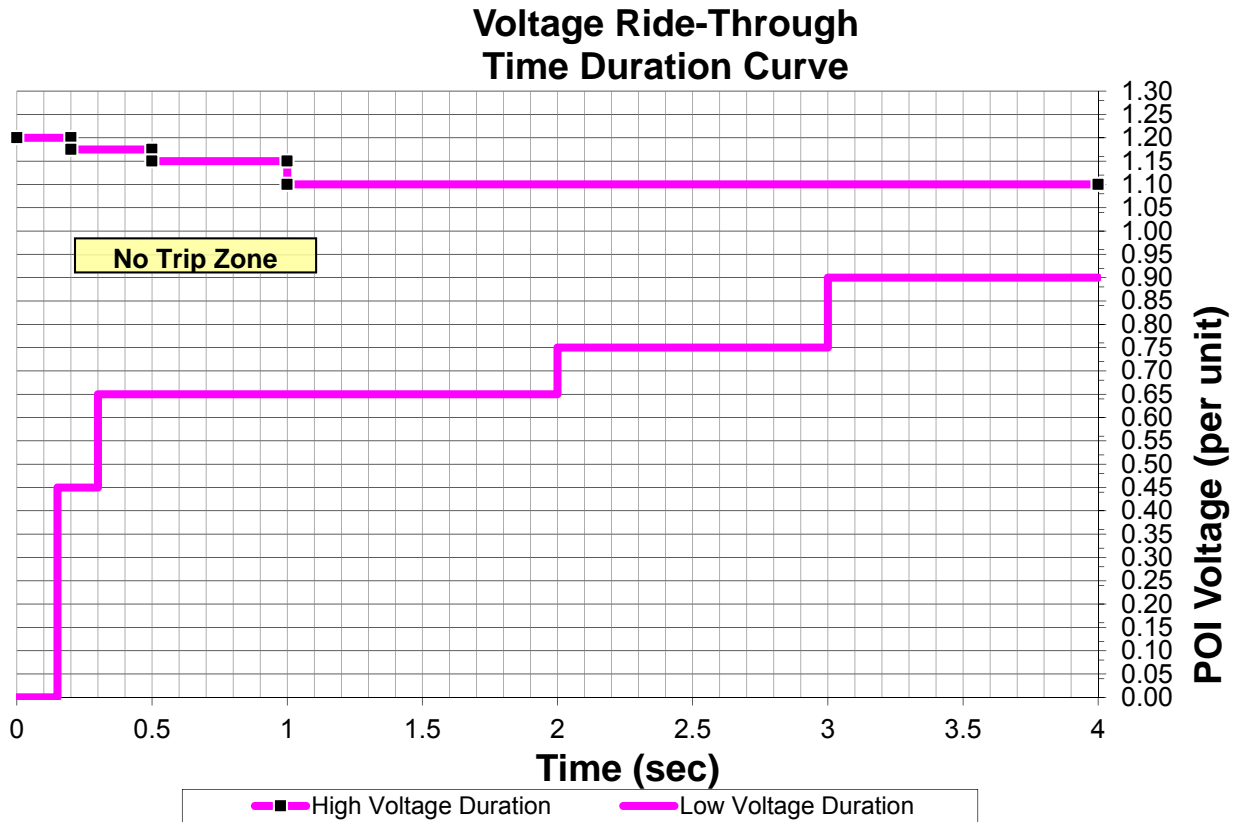
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
 - a. All of the units connected to the same transformer are online and operating.
 - b. All of the units are at full nameplate real-power output.
 - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
 - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1(X)
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
 - 4.1. Generator Owner
5. **Effective Date:**
 - 5.1. In those jurisdictions where regulatory approval is required:
 - 5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.2. In those jurisdictions where regulatory approval is not required:
 - 5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- 5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
- 5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

- R1.** Each Generator Owner that has generator frequency protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection²) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip in accordance with a ~~Special Protection System (SPS) or Remedial Action Scheme (RAS)~~.
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

¹ Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

² For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation³ that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice.
[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
 - Repair of the equipment causing the limitation that removes the limitation.
 - Replacement of the equipment causing the limitation with equipment that removes the limitation.
 - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

C. Measures

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement

³ Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer’s advice.

- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority (CEA) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases, the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2.

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	OR The Generator Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings. OR The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings. OR The Generator Owner failed to provide trip settings within 150 calendar days of a written request.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	

Standard PRC-024-1(X) — Generator Frequency and Voltage Protective Relay Settings

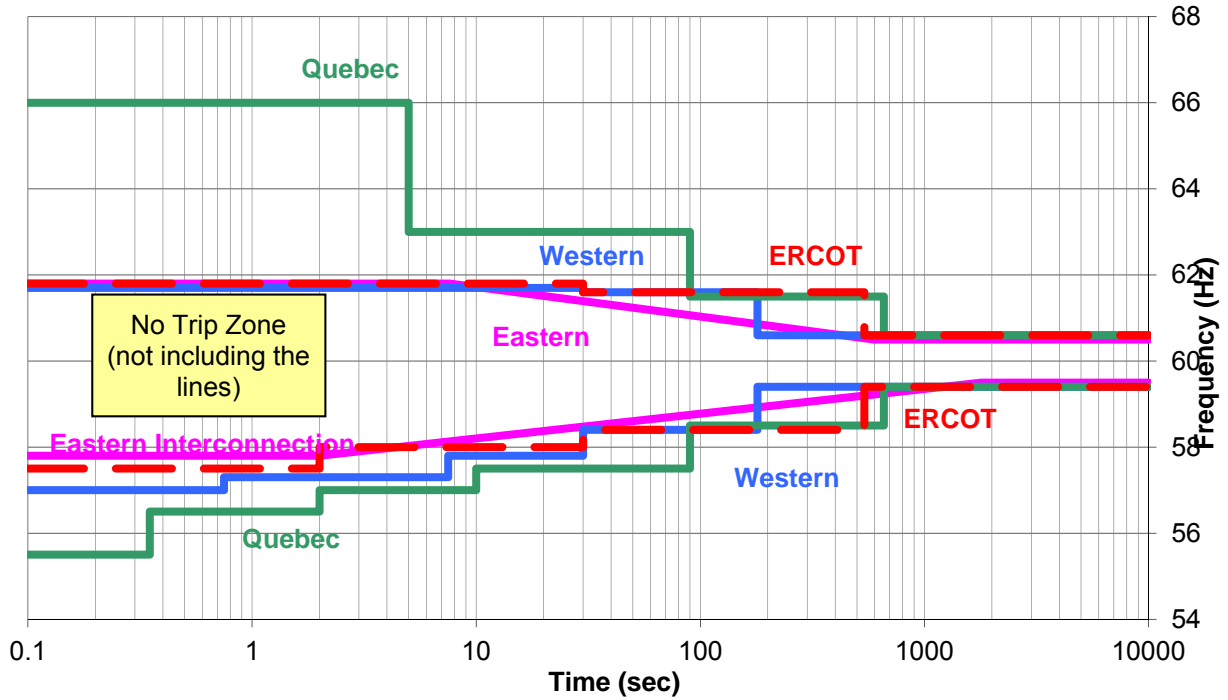
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
<u>1(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

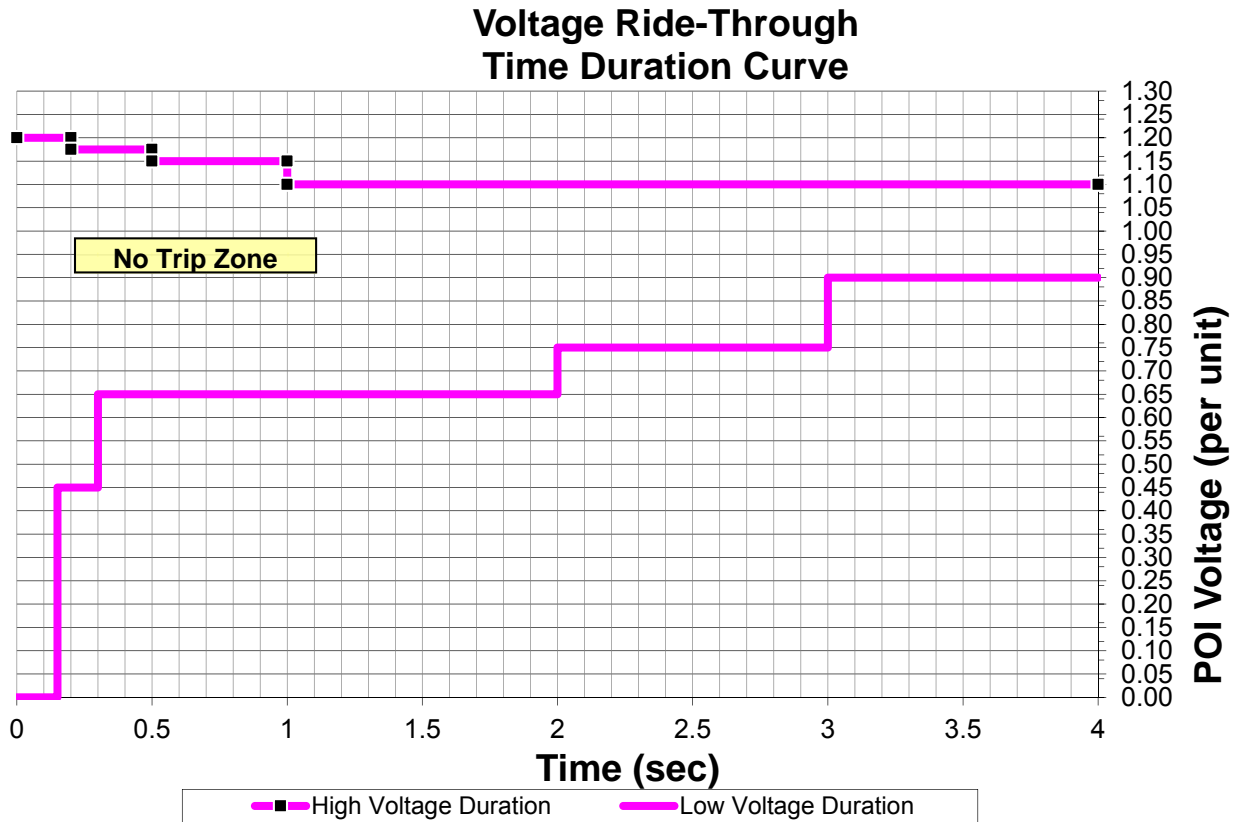
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
 - a. All of the units connected to the same transformer are online and operating.
 - b. All of the units are at full nameplate real-power output.
 - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
 - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

A. Introduction

1. **Title:** Generator Relay Loadability

2. **Number:** PRC-025-1(X)

Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. **Facilities:** The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.¹

3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

¹ These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1(X) Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.²

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

- R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.
[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]
- M1.** For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1(X) – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

² Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

PRC-025-1(X) – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.³
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

³ IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

⁴ Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
	2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation		
The same application continues with a different relay type below					
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)	
	If the relay is installed on the high-side of the GSU transformer use Option 19				
A different application starts below					
Unit auxiliary transformer(s) (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating	
		OR			
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
	If the relay is installed on the generator-side of the GSU transformer use Option 7	14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
The same application continues on the next page with a different relay type				

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	If the relay is installed on the generator-side of the GSU transformer use Option 10			
The same application continues on the next page with a different relay type				

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
<p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p>	<p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p>	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	<p>The same application continues on the next page with a different relay type</p>			

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
<p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p>	<p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p>	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** Generator Relay Loadability

2. **Number:** PRC-025-1(X)

Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.¹

3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

¹ These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1(X) Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.²

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

- R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.
[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]
- M1.** For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1(X) – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

² Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with PRC-025-1(X) – Attachment 1: Relay Settings, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

PRC-025-1(X) – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.³
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

³ IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

⁴ Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
	2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation		
The same application continues with a different relay type below					
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)	
	If the relay is installed on the high-side of the GSU transformer use Option 19				
A different application starts below					
Unit auxiliary transformer(s) (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating	
		OR			
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
	If the relay is installed on the generator-side of the GSU transformer use Option 7	14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
The same application continues on the next page with a different relay type				

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	If the relay is installed on the generator-side of the GSU transformer use Option 10			
The same application continues on the next page with a different relay type				

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
<p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p>	<p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p>	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	<p>The same application continues on the next page with a different relay type</p>			

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
<p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p>	<p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p>	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-2a(X)
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Purchasing Selling Entities.
5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	New
2	March 17, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	
2a	April 21, 2011	Added FERC approved Interpretation	
2a(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
 - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
 - 1.1.1** Status.
 - 1.1.2** MW or ampere loadings.
 - 1.1.3** MVA capability.
 - 1.1.4** Transformer tap and phase angle settings.
 - 1.1.5** Key voltages.
 - 1.2.** Generator data.
 - 1.2.1** Status.
 - 1.2.2** MW and MVAR capability.
 - 1.2.3** MW and MVAR net output.
 - 1.2.4** Status of automatic voltage control facilities.
 - 1.3.** Operating reserve.
 - 1.3.1** MW reserve available within ten minutes.
 - 1.4.** Balancing Authority demand.
 - 1.4.1** Instantaneous.
 - 1.5.** Interchange.
 - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
 - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
 - 1.5.3** Interchange Schedules for the next 24 hours.
 - 1.6.** Area Control Error and frequency.
 - 1.6.1** Instantaneous area control error.
 - 1.6.2** Clock hour area control error.
 - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
 - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
 - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
 - 2.3.** Forecast peak demand for current day and next day.
 - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

Requirement Number and Text of Requirement
<p>TOP-005-1 Requirement R3¹</p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or <u>degraded</u> Remedial Action Schemes. [Underline added for emphasis.]</i></p> <p>IRO-005-1 Requirement R12</p> <p>R12. Whenever a Remedial Action Scheme that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Remedial Action Scheme on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Remedial Action Scheme including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p>PRC-012-0(X) Requirements R1 and R1.3</p> <p>R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a RAS shall have a documented Regional Reliability Organization RAS review procedure to ensure that RAS comply with Regional criteria and NERC Reliability Standards. The Regional RAS review procedure shall include:</p> <p style="padding-left: 40px;">R1.3. Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p>
Background Information for Interpretation
<p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as</p>

¹ In the current version of the Standard (TOP-005-2a), this requirement is R2.

listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for RAS information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a RAS to operate as designed. If the loss of a communication channel will result in the failure of a RAS to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the RAS to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. **Title:** **Operational Reliability Information**
2. **Number:** TOP-005-2a(X)
3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Purchasing Selling Entities.
5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

- R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

- M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	New
2	March 17, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	
2a	April 21, 2011	Added FERC approved Interpretation	
<u>2a(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

- 1.** The following information shall be updated at least every ten minutes:
 - 1.1.** Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
 - 1.1.1** Status.
 - 1.1.2** MW or ampere loadings.
 - 1.1.3** MVA capability.
 - 1.1.4** Transformer tap and phase angle settings.
 - 1.1.5** Key voltages.
 - 1.2.** Generator data.
 - 1.2.1** Status.
 - 1.2.2** MW and MVAR capability.
 - 1.2.3** MW and MVAR net output.
 - 1.2.4** Status of automatic voltage control facilities.
 - 1.3.** Operating reserve.
 - 1.3.1** MW reserve available within ten minutes.
 - 1.4.** Balancing Authority demand.
 - 1.4.1** Instantaneous.
 - 1.5.** Interchange.
 - 1.5.1** Instantaneous actual interchange with each Balancing Authority.
 - 1.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
 - 1.5.3** Interchange Schedules for the next 24 hours.
 - 1.6.** Area Control Error and frequency.
 - 1.6.1** Instantaneous area control error.
 - 1.6.2** Clock hour area control error.
 - 1.6.3** System frequency at one or more locations in the Balancing Authority.
- 2.** Other operating information updated as soon as available.
 - 2.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.
 - 2.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.
 - 2.3.** Forecast peak demand for current day and next day.
 - 2.4.** Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded ~~special protection system~~ Remedial Action Schemes.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Appendix 2

Requirement Number and Text of Requirement
<p>TOP-005-1 Requirement R3¹</p> <p>Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.</p> <p><i>The above-referenced Attachment 1 — TOP-005-0 specifies the following data as item 2.6: New or degraded <u>special protection system Remedial Action Schemes</u>. [Underline added for emphasis.]</i></p> <p>IRO-005-1 Requirement R12</p> <p>R12. Whenever a <u>Special Protection System Remedial Action Scheme</u> that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that <u>Special Protection System Remedial Action Scheme</u> on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the <u>Special Protection System Remedial Action Scheme</u> including any <u>degradation</u> or potential failure to operate as expected. [Underline added for emphasis.]</p> <p>PRC-012-0(X) Requirements R1 and R1.3</p> <p>R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use a <u>SPS RAS</u> shall have a documented Regional Reliability Organization <u>SPS RAS</u> review procedure to ensure that <u>SPS RAS</u> comply with Regional criteria and NERC Reliability Standards. The Regional <u>SPS RAS</u> review procedure shall include:</p> <p>R1.3. Requirements to demonstrate that the <u>SPS RAS</u> shall be designed so that a single <u>SPSRAS</u> component failure, when the <u>SPSRAS</u> was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.</p>
Background Information for Interpretation
<p>The TOP-005-1 standard focuses on two key obligations. The first key obligation (Requirement R1) is a “responsibility mandate.” Requirement R1 establishes who is responsible for the obligation to provide operating data “required” by a Reliability Coordinator within the framework of the Reliability Coordinator requirements defined in the IRO standards. The second key obligation (Requirement R3) is a “performance mandate.” Requirement R3 defines the obligation to provide data “requested” by other reliability entities that is needed “to perform assessments and to coordinate operations.”</p> <p>The Attachment to TOP-005-1 is provided as a guideline of what “can be shared.” The Attachment is not an obligation of “what must be shared.” Enforceable NERC Requirements must be explicitly contained within a given Standard’s approved requirements. In this case, the standard only requires</p>

¹ In the current version of the Standard (TOP-005-2a), this requirement is R2.

data “upon request.” If a Reliability Coordinator or other reliability entity were to request data such as listed in the Attachment, then the entity being asked would be mandated by Requirements R1 and R3 to provide that data (including item 2.6, whether it is or is not in some undefined “degraded” state).

IRO-002-1 requires the Reliability Coordinator to have processes in place to support its reliability obligations (Requirement R2). Requirement R4 mandates that the Reliability Coordinator have communications processes in place to meet its reliability obligations, and Requirement R5 et al mandate the Reliability Coordinator to have the tools to carry out these reliability obligations.

IRO-003-2 (Requirements R1 and R2) requires the Reliability Coordinator to monitor the state of its system.

IRO-004-1 requires that the Reliability Coordinator carry out studies to identify Interconnection Reliability Operating Limits (Requirement R1) and to be aware of system conditions via monitoring tools and information exchange.

IRO-005-1 mandates that each Reliability Coordinator monitor predefined base conditions (Requirement R1), collect additional data when operating limits are or may be exceeded (Requirement R3), and identify actual or potential threats (Requirement R5). The basis for that request is left to each Reliability Coordinator. The Purpose statement of IRO-005-1 focuses on the Reliability Coordinator’s obligation to be aware of conditions that may have a “significant” impact upon its area and to communicate that information to others (Requirements R7 and R9). Please note: it is from this communication that Transmission Operators and Balancing Authorities would either obtain or would know to ask for [SPSRAS](#) information from another Transmission Operator.

The IRO-005-1 (Requirement R12) standard implies that degraded is a condition that will result in a failure to operate as designed. If the loss of a communication channel will result in the failure of a [SPSRAS](#) to operate as designed then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the [SPSRAS](#) to operate as designed, then such a condition can be, but is not mandated to be, reported.

Conclusion

The TOP-005-1 standard does not provide, nor does it require, a definition for the term “degraded.”

The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of a [SPSRAS](#) to operate as designed. If the loss of a communication channel will result in the failure of a [SPSRAS](#) to operate as designed, then the Transmission Operator would be mandated to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the [SPSRAS](#) to operate as designed, then such a condition can be, but is not mandated to be, reported.

To request a formal definition of the term degraded, the Reliability Standards Development Procedure requires the submittal of a Standards Authorization Request.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** May 13, 2009

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
 - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
 - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
 - R1.3.5. Have all projected firm transfers modeled.

- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
- R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(X)_R1, the Planning Authority and Transmission Planner shall each:
 - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.
 - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(X)_R1 and TPL-001-0.1(X)_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(X)_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised
0.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard TPL-001-0.1(X) — System Performance Under Normal Conditions

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
		System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^c : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^c , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^c : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^c : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^c : 5. Any two circuits of a multiple circuit towerline ^f	Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c	No No
	SLG Fault, with Delayed Clearing ^c (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c Planned/ Controlled ^c Planned/ Controlled ^c	No No No No

Standard TPL-001-0.1(X) — System Performance Under Normal Conditions

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <hr/> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Remedial Action Scheme to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** System Performance Under Normal (No Contingency) Conditions (Category A)
2. **Number:** TPL-001-0.1(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** May 13, 2009

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.
 - R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
 - R1.3.4. Have established normal (pre-contingency) operating procedures in place.
 - R1.3.5. Have all projected firm transfers modeled.

- R1.3.6.** Be performed for selected demand levels over the range of forecast system demands.
 - R1.3.7.** Demonstrate that system performance meets Table 1 for Category A (no contingencies).
 - R1.3.8.** Include existing and planned facilities.
 - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category A.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0.1(X)_R1, the Planning Authority and Transmission Planner shall each:
 - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.
 - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0.1(X)_R1 and TPL-001-0.1(X)_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0.1(X)_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date	Revised
0.1(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard TPL-001-0.1(X) — System Performance Under Normal Conditions

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
		System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^c : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^c , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^c : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^c : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^c : 5. Any two circuits of a multiple circuit towerline ^f	Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c	No No
	SLG Fault, with Delayed Clearing ^c (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c Planned/ Controlled ^c Planned/ Controlled ^c	No No No No

Standard TPL-001-0.1(X) — System Performance Under Normal Conditions

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <hr/> <p>5. Breaker (failure or internal Fault)</p> <hr/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Special Protection System Remedial Action Scheme (or remedial action scheme) to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Special Protection System Remedial Action Scheme (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p>	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements
2. **Number:** TPL-001-4(X)
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**
 - 4.1. **Functional Entity**
 - 4.1.1. Planning Coordinator.
 - 4.1.2. Transmission Planner.
5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4(X), Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4(X):

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

- R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** System models shall represent:
- 1.1.1.** Existing Facilities
 - 1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
 - 1.1.3.** New planned Facilities and changes to existing Facilities
 - 1.1.4.** Real and reactive Load forecasts
 - 1.1.5.** Known commitments for Firm Transmission Service and Interchange
 - 1.1.6.** Resources (supply or demand side) required for Load
- R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:
- 2.1.1.** System peak Load for either Year One or year two, and for year five.
 - 2.1.2.** System Off-Peak Load for one of the five years.
 - 2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.
 - 2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
 - Real and reactive forecasted Load.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
 - Duration or timing of known Transmission outages.
- 2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- 2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
- 2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- 2.4.2.** System Off-Peak Load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, Load forecast, or dynamic Load model assumptions.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- 2.5.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.
- 2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements:
- 2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.
- 2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
- 2.7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
 - Installation, modification, or removal of Protection Systems or Remedial Action Schemes
 - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
 - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
 - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
 - Use of rate applications, DSM, new technologies, or other initiatives.
- 2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

- 2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
 - 2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:
 - 2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.
 - 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
 - R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
 - 3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.
 - 3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.
 - 3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:
 - 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
 - 3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
 - 3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.
 - 3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
 - 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

- 3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
- 3.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.
- R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
 - 4.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.
 - 4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.
 - 4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
 - 4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.
 - 4.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.
 - 4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :
 - 4.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
 - 4.3.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
 - 4.3.1.2.** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

- 4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
 - 4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.
 - 4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
 - 4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
 - 4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.
- R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [*Violation Risk Factor: Low*] [*Time Horizon: Long-term Planning*]
- R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- 8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

- a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

- f. Applicable Facility Ratings shall not be exceeded.
- g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

- j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault ⁷	N/A	EHV, HV	No ⁹	No ¹²
		2. Bus Section Fault	SLG	EHV	No ⁹	No
				HV	Yes	Yes
		3. Internal Breaker Fault ⁸ (non-Bus-tie Breaker)	SLG	EHV	No ⁹	No
HV	Yes			Yes		
4. Internal Breaker Fault (Bus-tie Breaker) ⁸	SLG	EHV, HV	Yes	Yes		

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Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments ⁹	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency <i>(Fault plus stuck breaker¹⁰)</i>	Normal System	Loss of multiple elements caused by a stuck breaker ¹⁰ (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section	SLG	EHV	No ⁹	No
		6. Loss of multiple elements caused by a stuck breaker ¹⁰ (Bus-tie Breaker) attempting to clear a Fault on the associated bus		HV	Yes	Yes
				SLG	EHV, HV	Yes
P5 Multiple Contingency <i>(Fault plus relay failure to operate)</i>	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay ¹³ protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section	SLG	EHV	No ⁹	No
				HV	Yes	Yes
P6 Multiple Contingency <i>(Two overlapping singles)</i>	Loss of one of the following followed by System adjustments. ⁹ 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶ 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG			

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Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P7 Multiple Contingency <i>(Common Structure)</i>	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ¹¹ 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Table 1 – Steady State & Stability Performance Extreme Events	
<p>Steady State & Stability For all extreme events evaluated:</p> <ol style="list-style-type: none"> a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified. 	
<p>Steady State</p> <ol style="list-style-type: none"> 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. Loss of a tower line with three or more circuits.¹¹ b. Loss of all Transmission lines on a common Right-of-Way¹¹. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: <ol style="list-style-type: none"> a. Loss of two generating stations resulting from conditions such as: <ol style="list-style-type: none"> i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances. 	<p>Stability</p> <ol style="list-style-type: none"> 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. 3Ø fault on generator with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

**Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)**

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3 \emptyset) are the fault types that must be evaluated in Stability simulations for the event described. A 3 \emptyset or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
 - a. Date, time, and location for the meeting
 - b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
 - c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
 - a. System Load level and estimated annual hours of exposure at or above that Load level
 - b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
 - a. The estimated number and type of customers affected

- b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
 - a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
 - b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

- M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.
- M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

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	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</p>	<p>the categories (P2 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</p>	<p>OR</p> <p>The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>
R4	<p>The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>
R5	N/A	N/A	N/A	<p>The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.</p>
R6	N/A	N/A	N/A	<p>The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.</p>

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	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.</p> <p>OR</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.</p>

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 6, 2014	The NERC Board of Trustees adopted a revision to the VRF of Requirement 1 from Medium to High in TPL-001-4.	

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4(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
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A. Introduction

1. **Title:** Transmission System Planning Performance Requirements
2. **Number:** TPL-001-4(X)
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**
 - 4.1. **Functional Entity**
 - 4.1.1. Planning Coordinator.
 - 4.1.2. Transmission Planner.
5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4(X), Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4(X):

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

- R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** System models shall represent:
- 1.1.1.** Existing Facilities
 - 1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
 - 1.1.3.** New planned Facilities and changes to existing Facilities
 - 1.1.4.** Real and reactive Load forecasts
 - 1.1.5.** Known commitments for Firm Transmission Service and Interchange
 - 1.1.6.** Resources (supply or demand side) required for Load
- R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:
- 2.1.1.** System peak Load for either Year One or year two, and for year five.
 - 2.1.2.** System Off-Peak Load for one of the five years.
 - 2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.
 - 2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
 - Real and reactive forecasted Load.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
 - Duration or timing of known Transmission outages.
- 2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- 2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
- 2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- 2.4.2.** System Off-Peak Load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, Load forecast, or dynamic Load model assumptions.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- 2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.
- 2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:
- 2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.
- 2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
- 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
 - Installation, modification, or removal of Protection Systems or ~~Special Protection System~~ Remedial Action Schemes
 - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
 - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
 - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
 - Use of rate applications, DSM, new technologies, or other initiatives.
- 2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

- or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.
- 2.7.4.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
- 2.8.** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:
- 2.8.1.** List System deficiencies and the associated actions needed to achieve required System performance.
- 2.8.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.
- R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- 3.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.
- 3.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.
- 3.3.** Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:
- 3.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
- 3.3.1.1.** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
- 3.3.1.2.** Tripping of Transmission elements where relay loadability limits are exceeded.
- 3.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
- 3.4.** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies

to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

- 3.4.1.** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
- 3.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.
- R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
 - 4.1.** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.
 - 4.1.1.** For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a ~~Special Protection System~~Remedial Action Scheme is not considered pulling out of synchronism.
 - 4.1.2.** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.
 - 4.1.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.
 - 4.2.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.
 - 4.3.** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :
 - 4.3.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
 - 4.3.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.
 - 4.3.1.2.** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or

- assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
- 4.3.1.3.** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.
- 4.3.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.
- 4.4.** Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
- 4.4.1.** Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
- 4.5.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.
- R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- R7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [*Violation Risk Factor: Low*] [*Time Horizon: Long-term Planning*]
- R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- 8.1.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide

a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

- a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

- f. Applicable Facility Ratings shall not be exceeded.
- g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

- j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault ⁷	N/A	EHV, HV	No ⁹	No ¹²
		2. Bus Section Fault	SLG	EHV	No ⁹	No
				HV	Yes	Yes
		3. Internal Breaker Fault ⁸ (non-Bus-tie Breaker)	SLG	EHV	No ⁹	No
HV	Yes			Yes		
4. Internal Breaker Fault (Bus-tie Breaker) ⁸	SLG	EHV, HV	Yes	Yes		

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Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments ⁹	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency <i>(Fault plus stuck breaker¹⁰)</i>	Normal System	Loss of multiple elements caused by a stuck breaker ¹⁰ (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section	SLG	EHV	No ⁹	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker ¹⁰ (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency <i>(Fault plus relay failure to operate)</i>	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay ¹³ protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section	SLG	EHV	No ⁹	No
				HV	Yes	Yes
P6 Multiple Contingency <i>(Two overlapping singles)</i>	Loss of one of the following followed by System adjustments. ⁹ 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶ 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG			

Standard TPL-001-4(X) — Transmission System Planning Performance Requirements

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P7 Multiple Contingency <i>(Common Structure)</i>	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ¹¹ 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Table 1 – Steady State & Stability Performance Extreme Events	
<p>Steady State & Stability For all extreme events evaluated:</p> <ol style="list-style-type: none"> a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency. b. Simulate Normal Clearing unless otherwise specified. 	
<p>Steady State</p> <ol style="list-style-type: none"> 1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. Loss of a tower line with three or more circuits.¹¹ b. Loss of all Transmission lines on a common Right-of-Way¹¹. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a generating station. e. Loss of a large Load or major Load center. 3. Wide area events affecting the Transmission System based on System topology such as: <ol style="list-style-type: none"> a. Loss of two generating stations resulting from conditions such as: <ol style="list-style-type: none"> i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation. ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances. 	<p>Stability</p> <ol style="list-style-type: none"> 1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. 3Ø fault on generator with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault. f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

**Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)**

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3 \emptyset) are the fault types that must be evaluated in Stability simulations for the event described. A 3 \emptyset or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
 - a. Date, time, and location for the meeting
 - b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
 - c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
 - a. System Load level and estimated annual hours of exposure at or above that Load level
 - b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
 - a. The estimated number and type of customers affected

- b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
 - a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
 - b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

- M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.
- M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

Standard TPL-001-4(X) — Transmission System Planning Performance Requirements

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</p>	<p>the categories (P2 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</p>	<p>OR</p> <p>The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>
R4	<p>The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>
R5	N/A	N/A	N/A	<p>The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.</p>
R6	N/A	N/A	N/A	<p>The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.</p>

Standard TPL-001-4(X) — Transmission System Planning Performance Requirements

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.</p> <p>OR</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.</p>

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 6, 2014	The NERC Board of Trustees adopted a revision to the VRF of Requirement 1 from Medium to High in TPL-001-4.	

Standard TPL-001-4(X) — Transmission System Planning Performance Requirements

<u>4(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

A. Introduction

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0b(X)
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
 - 4.1.** Planning Authority
 - 4.2.** Transmission Planner
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1.** Be made annually.
 - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
 - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
 - R1.3.5.** Have all projected firm transfers modeled.
 - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

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- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b(X)_R1, the Planning Authority and Transmission Planner shall each:
 - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.
 - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0b(X)_R1 and TPL-002-0b(X)_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0b(X)_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

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1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation
0b(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^c : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^c , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^c : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^c : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^c :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure):	6. Generator	Yes	Planned/ Controlled ^c	No
	7. Transformer	Yes	Planned/ Controlled ^c	No
	8. Transmission Circuit	Yes	Planned/ Controlled ^c	No
	9. Bus Section	Yes	Planned/ Controlled ^c	No

Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table>	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
	1. Generator	3. Transformer				
2. Transmission Circuit	4. Bus Section					
<p>3Ø Fault, with Normal Clearing^e:</p> <p>5. Breaker (failure or internal Fault)</p> <hr style="border-top: 1px dashed black;"/> <p>6. Loss of towerline with three or more circuits</p> <p>7. All transmission lines on a common right-of way</p> <p>8. Loss of a substation (one voltage level plus transformers)</p> <p>9. Loss of a switching station (one voltage level plus transformers)</p> <p>10. Loss of all generating units at a station</p> <p>11. Loss of a large Load or major Load center</p> <p>12. Failure of a fully redundant Remedial Action Scheme to operate when required</p> <p>13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate</p> <p>14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.</p>						

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:**

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from Ameren on July 25, 2007:**

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from MISO on August 9, 2007:**

MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

Appendix 2

Requirement Number and Text of Requirement
<p>R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p>R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>
Background Information for Interpretation
<p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> 1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).” 2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).” 3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.” <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> 1. Generator 2. Transmission Circuit 3. Transformer <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing^e:</p> <ol style="list-style-type: none"> 4. Single Pole (dc) Line <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p>
Conclusion
<p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

A. Introduction

- 1. Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)
- 2. Number:** TPL-002-0b(X)
- 3. Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
- 4. Applicability:**
 - 4.1.** Planning Authority
 - 4.2.** Transmission Planner
- 5. Effective Date:** Immediately after approval of applicable regulatory authorities.

B. Requirements

- R1.** The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1.** Be made annually.
 - R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1.** Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
 - R1.3.2.** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.3.** Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.4.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.
 - R1.3.5.** Have all projected firm transfers modeled.
 - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system Demands.

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- R1.3.7.** Demonstrate that system performance meets Category B contingencies.
- R1.3.8.** Include existing and planned facilities.
- R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
- R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
- R1.3.11.** Include the effects of existing and planned control devices.
- R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category B of Table I.
- R1.5.** Consider all contingencies applicable to Category B.
- R2.** When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0b(X)_R1, the Planning Authority and Transmission Planner shall each:
 - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.
 - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0b(X)_R1 and TPL-002-0b(X)_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0b(X)_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

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1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0a	July 30, 2008	Adopted by NERC Board of Trustees	New
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0b	November 5, 2009	Added Appendix 2 – Interpretation of R1.3.10 approved by BOT on November 5, 2009	Interpretation
0b	September 15, 2011	FERC Order issued approving the Interpretation of R1.3.10 (FERC Order becomes effective October 24, 2011)	Interpretation
<u>0b(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^c : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^c , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^c : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^c : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^c :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure):	6. Generator	Yes	Planned/ Controlled ^c	No
	7. Transformer	Yes	Planned/ Controlled ^c	No
	8. Transmission Circuit	Yes	Planned/ Controlled ^c	No
	9. Bus Section	Yes	Planned/ Controlled ^c	No

Standard TPL-002-0b(X) — System Performance Following Loss of a Single BES Element

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas.
	<p>3Ø Fault, with Normal Clearing^e:</p> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or Remedial Action Scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	<ul style="list-style-type: none"> ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2
Received from MISO on August 9, 2007:**

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from Ameren on July 25, 2007:**

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

**Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12
Received from MISO on August 9, 2007:**

MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

Appendix 2

Requirement Number and Text of Requirement
<p>R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).</p> <p>R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.</p>
Background Information for Interpretation
<p>Requirement R1.3 and sub-requirement R1.3.10 of standard TPL-002-0a contain three key obligations:</p> <ol style="list-style-type: none"> 1. That the assessment is supported by “study and/or system simulation testing that addresses each the following categories, showing system performance following Category B of Table 1 (single contingencies).” 2. “...these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).” 3. “Include the effects of existing and planned protection systems, including any backup or redundant systems.” <p><i>Category B of Table 1 (single Contingencies) specifies:</i></p> <p>Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:</p> <ol style="list-style-type: none"> 1. Generator 2. Transmission Circuit 3. Transformer <p>Loss of an Element without a Fault.</p> <p>Single Pole Block, Normal Clearing^e:</p> <ol style="list-style-type: none"> 4. Single Pole (dc) Line <p><i>Note e specifies:</i></p> <p>e) Normal Clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.</p> <p>The NERC Glossary of Terms defines Normal Clearing as “A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.”</p>
Conclusion
<p>TPL-002-0a requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.</p> <p>This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or</p>

More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).

TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.

In regards to PacifiCorp’s comments on the material impact associated with this interpretation, the interpretation team has the following comment:

Requirement R2.1 requires “a written summary of plans to achieve the required system performance,” including a schedule for implementation and an expected in-service date that considers lead times necessary to implement the plan. Failure to provide such summary may lead to noncompliance that could result in penalties and sanctions.

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

A. Introduction

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** April 23, 2010

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
 - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

- R1.3.5.** Have all projected firm transfers modeled.
 - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
 - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
 - R1.3.8.** Include existing and planned facilities.
 - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
 - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
 - R1.3.11.** Include the effects of existing and planned control devices.
 - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0b(X)_R1, the Planning Authority and Transmission Planner shall each:
 - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.
 - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0b(X)_R1 and TPL-003-0b(X)_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0b(X)_R3.

D. Compliance

- 1. Compliance Monitoring Process**

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
0b	February 7, 2013	Interpretation adopted by NERC Board of Trustees	
0b	June 20, 2013	FERC order issued approving Interpretation	
0b(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading ^c Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^e : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^e : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^e , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^e : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^e : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^e :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
	SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled ^c	No
7. Transformer	Yes	Planned/ Controlled ^c	No	
8. Transmission Circuit	Yes	Planned/ Controlled ^c	No	
9. Bus Section	Yes	Planned/ Controlled ^c	No	

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <hr/> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Remedial Action Scheme to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

Appendix 2

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

Date submitted: December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	R1.3.1 Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	R1.5. Consider all contingencies applicable to Category C.
TPL-004-0	R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	R1.4. Consider all contingencies applicable to Category D.

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

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clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)¹ (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(X) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects² of either "stuck breaker" or "protection system failure" contingency³, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1⁴ requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

¹ NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

² As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

³ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

⁴ "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

Question 2: For the phrase “Delayed Clearing⁵” used in Category C⁶ contingencies 6-9 and Category D⁷ contingencies 1-4, to what extent does the description in Table 1, footnote (e)⁸ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects⁹ of either “stuck breaker” or “protection system failure” contingency¹⁰, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

⁵ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

⁶ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

⁷ As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

⁸ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

⁹ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

¹⁰ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 ϕ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

Question 2

For the phrase “Delayed Clearing¹¹” used in Category C¹² contingencies 6-9 and Category D¹³ contingencies 1-4, to what extent does the description in Table 1, footnote (e)¹⁴ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

¹¹ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

¹² As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

¹³ As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

¹⁴ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

A. Introduction

1. **Title:** System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
2. **Number:** TPL-003-0b(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** April 23, 2010

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
 - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

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- R1.3.5.** Have all projected firm transfers modeled.
 - R1.3.6.** Be performed and evaluated for selected demand levels over the range of forecast system demands.
 - R1.3.7.** Demonstrate that System performance meets Table 1 for Category C contingencies.
 - R1.3.8.** Include existing and planned facilities.
 - R1.3.9.** Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.
 - R1.3.10.** Include the effects of existing and planned protection systems, including any backup or redundant systems.
 - R1.3.11.** Include the effects of existing and planned control devices.
 - R1.3.12.** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.
- R1.4.** Address any planned upgrades needed to meet the performance requirements of Category C.
- R1.5.** Consider all contingencies applicable to Category C.
- R2.** When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0b(X)_R1, the Planning Authority and Transmission Planner shall each:
 - R2.1.** Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:
 - R2.1.1.** Including a schedule for implementation.
 - R2.1.2.** Including a discussion of expected required in-service dates of facilities.
 - R2.1.3.** Consider lead times necessary to implement plans.
 - R2.2.** Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.
- R3.** The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0b(X)_R1 and TPL-003-0b(X)_R2.
- M2.** The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0b(X)_R3.

D. Compliance

- 1. Compliance Monitoring Process**

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1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item “e” on page 8.	Errata
0a	July 30, 2008	Adopted by NERC Board of Trustees	
0a	October 23, 2008	Added Appendix 1 – Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO	Revised
0a	April 23, 2010	FERC approval of interpretation of TPL-003-0 R1.3.12	Interpretation
0b	February 7, 2013	Interpretation adopted by NERC Board of Trustees	
0b	June 20, 2013	FERC order issued approving Interpretation	
<u>0b(X)</u>	<u>TBD</u>	<u>Adopted by the NERC Board of Trustees</u>	<u>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</u>

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading ^c Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^e : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^e : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^e , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^e : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^e : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^e :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
	SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled ^c	No
7. Transformer	Yes	Planned/ Controlled ^c	No	
8. Transmission Circuit	Yes	Planned/ Controlled ^c	No	
9. Bus Section	Yes	Planned/ Controlled ^c	No	

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) <hr/> <ol style="list-style-type: none"> 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or Remedial Action Scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation of TPL-002-0 Requirements R1.3.2 and R1.3.12 and TPL-003-0 Requirements R1.3.2 and R1.3.12 for Ameren and MISO

NERC received two requests for interpretation of identical requirements (Requirements R1.3.2 and R1.3.12) in TPL-002-0 and TPL-003-0 from the Midwest ISO and Ameren. These requirements state:

TPL-002-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

TPL-003-0:

[To be valid, the Planning Authority and Transmission Planner assessments shall:]

- R1.3** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
- R1.3.2** Cover critical system conditions and study years as deemed appropriate by the responsible entity.
- R1.3.12** Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Requirement R1.3.2

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from Ameren on July 25, 2007:

Ameren specifically requests clarification on the phrase, 'critical system conditions' in R1.3.2. Ameren asks if compliance with R1.3.2 requires multiple contingent generating unit Outages as part of possible generation dispatch scenarios describing critical system conditions for which the system shall be planned and modeled in accordance with the contingency definitions included in Table 1.

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Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 Received from MISO on August 9, 2007:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.2 was developed by the NERC Planning Committee on March 13, 2008:

The selection of a credible generation dispatch for the modeling of critical system conditions is within the discretion of the Planning Authority. The Planning Authority was renamed “Planning Coordinator” (PC) in the Functional Model dated February 13, 2007. (TPL -002 and -003 use the former “Planning Authority” name, and the Functional Model terminology was a change in name only and did not affect responsibilities.)

- Under the Functional Model, the Planning Coordinator “Provides and informs Resource Planners, Transmission Planners, and adjacent Planning Coordinators of the methodologies and tools for the simulation of the transmission system” while the Transmission Planner “Receives from the Planning Coordinator methodologies and tools for the analysis and development of transmission expansion plans.” A PC’s selection of “critical system conditions” and its associated generation dispatch falls within the purview of “methodology.”

Furthermore, consistent with this interpretation, a Planning Coordinator would formulate critical system conditions that may involve a range of critical generator unit outages as part of the possible generator dispatch scenarios.

Both TPL-002-0 and TPL-003-0 have a similar measure M1:

- M1.** The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 [or TPL-003-0_R1] and TPL-002-0_R2 [or TPL-003-0_R2].”

The Regional Reliability Organization (RRO) is named as the Compliance Monitor in both standards. Pursuant to Federal Energy Regulatory Commission (FERC) Order 693, FERC eliminated the RRO as the appropriate Compliance Monitor for standards and replaced it with the Regional Entity (RE). See paragraph 157 of Order 693. Although the referenced TPL standards still include the reference to the RRO, to be consistent with Order 693, the RRO is replaced by the RE as the Compliance Monitor for this interpretation. As the Compliance Monitor, the RE determines what a “valid assessment” means when evaluating studies based upon specific sub-requirements in R1.3 selected by the Planning Coordinator and the Transmission Planner. If a PC has Transmission Planners in more than one region, the REs must coordinate among themselves on compliance matters.

Requirement R1.3.12

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from Ameren on July 25, 2007:

Ameren also asks how the inclusion of planned outages should be interpreted with respect to the contingency definitions specified in Table 1 for Categories B and C. Specifically, Ameren asks if R1.3.12 requires that the system be planned to be operated during those conditions associated with planned outages consistent with the performance requirements described in Table 1 plus any unidentified outage.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 Received from MISO on August 9, 2007:

MISO asks if the term “planned outages” means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard?

The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a “contingency” as defined in the *NERC Glossary of Terms Used in Standards*.

Standard TPL-003-0b(X) — System Performance Following Loss of Two or More BES Elements

Appendix 2

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

Date submitted: December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.3.7 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	R1.3.1 Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	R1.5. Consider all contingencies applicable to Category C.
TPL-004-0	R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	R1.4. Consider all contingencies applicable to Category D.

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning

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clarification regarding the following questions about the listed standards, requirements and terms. More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)¹ (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a(X) (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects² of either "stuck breaker" or "protection system failure" contingency³, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1⁴ requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

¹ NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

² As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.3.10. and/or TPL-004-0(X), Requirement R1.3.7.

³ As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

⁴ "Be performed and evaluated only for those Category (TPL-003-0a(X) Category C and TPL-004-0(X) Category D) contingencies that would produce the more severe system results or impacts."

Question 2: For the phrase “Delayed Clearing⁵” used in Category C⁶ contingencies 6-9 and Category D⁷ contingencies 1-4, to what extent does the description in Table 1, footnote (e)⁸ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects⁹ of either “stuck breaker” or “protection system failure” contingency¹⁰, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

⁵ As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

⁶ As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5.

⁷ As required by NERC Reliability Standard TPL-004-0(X), Requirement R1.4.

⁸ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

⁹ As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.3.10. and/or TPL-004-0(X), Requirement R1.3.7.

¹⁰ As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

Response 1

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 ϕ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

Question 2

For the phrase “Delayed Clearing¹¹” used in Category C¹² contingencies 6-9 and Category D¹³ contingencies 1-4, to what extent does the description in Table 1, footnote (e)¹⁴ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

¹¹ As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5. and/or TPL-004-0(X), Requirement R1.4.

¹² As required by NERC Reliability Standard TPL-003-0a(X), Requirement R1.5.

¹³ As required by NERC Reliability Standard TPL-004-0(X), Requirement R1.4.

¹⁴ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

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A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0a(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five).
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
 - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.4. Have all projected firm transfers modeled.
 - R1.3.5. Include existing and planned facilities.
 - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
 - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
 - R1.3.8. Include the effects of existing and planned control devices.

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R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0a(X)_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0a(X)_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	February 7, 2013	Interpretation adopted by NERC Board of Trustees	

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0a	June 20, 2013	Interpretation approved in FERC order	
0a(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

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Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^c : 1. Bus Section	Yes	Planned/ Controlled ^c	No
	2. Breaker (failure or internal Fault)	Yes	Planned/ Controlled ^c	No
	SLG or 3Ø Fault, with Normal Clearing ^c , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^c : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^c : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^c :	Yes	Planned/ Controlled ^c	No
	5. Any two circuits of a multiple circuit towerline ^f	Yes	Planned/ Controlled ^c	No
	SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure): 6. Generator	Yes	Planned/ Controlled ^c	No
7. Transformer	Yes	Planned/ Controlled ^c	No	
8. Transmission Circuit	Yes	Planned/ Controlled ^c	No	
9. Bus Section	Yes	Planned/ Controlled ^c	No	

Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <table border="0"> <tr> <td>1. Generator</td> <td>3. Transformer</td> </tr> <tr> <td>2. Transmission Circuit</td> <td>4. Bus Section</td> </tr> </table> <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <hr/> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) <hr/> 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Remedial Action Scheme to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Remedial Action Scheme in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	1. Generator	3. Transformer	2. Transmission Circuit	4. Bus Section	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
1. Generator	3. Transformer					
2. Transmission Circuit	4. Bus Section					

- a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.
- b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.
- c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.
- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
- e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.
- f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Appendix 1

Interpretation 2012-INT-02: Response to Request for Interpretation of TPL-003-0a, Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, Requirements R1.3.1, R1.3.7 and R1.4 for the System Protection and Control Subcommittee

Date submitted: December 12, 2011

The following interpretations of TPL-003-0a, System Performance Following Loss of Two or More Bulk Electric System Elements (Category C), Requirements R1.3.1, R1.3.10 and R1.5 and TPL-004-0, System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D), Requirements R1.3.1, R1.37 and R1.4 were developed by members of the Assess Transmission Future Needs Standard Drafting Team (ATFNSTD), Protection System Misoperations Standard Development Team (PSMSDT), and Protection System Maintenance and Testing Standard Drafting Team (PSMTSDT).

Standard	Requirement (and text)
TPL-003-0a	R1.3.1 Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-003-0a	R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-003-0a	R1.5. Consider all contingencies applicable to Category C.
TPL-004-0	R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
TPL-004-0	R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	R1.4. Consider all contingencies applicable to Category D.

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

On March 30, 2009, NERC issued an [Industry Advisory — Protection System Single Point of Failure](#)¹ (i.e., NERC Alert) for three significant events. One of which, the Westwing outage (June 14, 2004) was caused by failure of a single auxiliary relay that initiated both breaker tripping and the breaker failure protection. Since breaker tripping and breaker failure protection both shared the same auxiliary relay, there was no independence between breaker tripping and breaker failure protection systems, therefore causing both protection systems to not operate for the single component failure of the auxiliary relay. The failure of this auxiliary relay is known as a "single point of failure." It is not clear whether this situation is comprehensively addressed by the applicable entities when making a valid assessment of system performance for both Category C and D contingencies.

Question 1: For the parenthetical "(stuck breaker or protection system failure)" in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects² of either "stuck breaker" or "protection system failure" contingency³, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

There is a lack of clarity whether R1.3.1⁴ requires an entity to assess which contingency causes the most severe system results or impacts (R1.3.1) and this ambiguity could result in a potential reliability gap. Whether the simulation of a stuck breaker or protection system failure will produce the worst result depends on the protection system design. For example when a protection system is fully redundant, a protection system failure will not affect fault clearing; therefore, a stuck breaker would result in more severe system results or impacts. However, when a protection system failure affects fault clearing, the fault clearing time may be longer than the breaker failure protection clearing time for a stuck breaker contingency and may result in tripping of additional system elements, resulting in a more severe system response.

¹ NERC Website: (<http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf>)

² As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

³ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

⁴ "Be performed and evaluated only for those Category (TPL-003-0a Category C and TPL-004-0 Category D) contingencies that would produce the more severe system results or impacts."

Question 2: For the phrase “Delayed Clearing⁵” used in Category C⁶ contingencies 6-9 and Category D⁷ contingencies 1-4, to what extent does the description in Table 1, footnote (e)⁸ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects⁹ of either “stuck breaker” or “protection system failure” contingency¹⁰, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

⁵ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

⁶ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

⁷ As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

⁸ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

⁹ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

¹⁰ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 ϕ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

Question 2

For the phrase “Delayed Clearing¹¹” used in Category C¹² contingencies 6-9 and Category D¹³ contingencies 1-4, to what extent does the description in Table 1, footnote (e)¹⁴ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

¹¹ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

¹² As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

¹³ As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

¹⁴ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.

A. Introduction

1. **Title:** System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
2. **Number:** TPL-004-0a(X)
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
 - 4.1. Planning Authority
 - 4.2. Transmission Planner
5. **Effective Date:** April 1, 2005

B. Requirements

- R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall:
 - R1.1. Be made annually.
 - R1.2. Be conducted for near-term (years one through five).
 - R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).
 - R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.
 - R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.
 - R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.
 - R1.3.4. Have all projected firm transfers modeled.
 - R1.3.5. Include existing and planned facilities.
 - R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
 - R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
 - R1.3.8. Include the effects of existing and planned control devices.

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Consider all contingencies applicable to Category D.

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0a(X)-R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0a(X)-R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0a	February 7, 2013	Interpretation adopted by NERC Board of Trustees	

Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

0a	June 20, 2013	Interpretation approved in FERC order	
0a(X)	TBD	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS

Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating ^a	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No ^b No ^b No ^b No ^b	No No No No
	Single Pole Block, Normal Clearing ^c : 4. Single Pole (dc) Line	Yes	No ^b	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing ^c : 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c	No No
	SLG or 3Ø Fault, with Normal Clearing ^c , Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing ^c : 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled ^c	No
	Bipolar Block, with Normal Clearing ^c : 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing ^c : 5. Any two circuits of a multiple circuit towerline ^f	Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c	No No
	SLG Fault, with Delayed Clearing ^e (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled ^c Planned/ Controlled ^c Planned/ Controlled ^c	No No No No

Standard TPL-004-0a(X) — System Performance Following Extreme BES Events

<p>D^d</p> <p>Extreme event resulting in two or more (multiple) elements removed or Cascading out of service</p>	<p>3Ø Fault, with Delayed Clearing^e (stuck breaker or protection system failure):</p> <ol style="list-style-type: none"> 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section <hr/> <p>3Ø Fault, with Normal Clearing^e:</p> <ol style="list-style-type: none"> 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or Remedial Action Scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization. 	<p>Evaluate for risks and consequences.</p> <ul style="list-style-type: none"> ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.
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- d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.
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TPL-004-0	R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems.
TPL-004-0	R1.4. Consider all contingencies applicable to Category D.

Please explain the clarification needed (as submitted).

This interpretation request has been developed to address Commission concerns related to the term “Single Point of Failure” and how it relates to system performance and contingency planning clarification regarding the following questions about the listed standards, requirements and terms.

More specifically, clarification is needed about the comprehensive study of system performance relating to Table 1's, Category C and D contingency of a "protection system failure" and specifically the impact of failed components (i.e., "Single Point of Failure"). It is not entirely clear whether a valid assessment of a protection system failure includes evaluation of shared or non-redundant protection system components. Protection systems that have a shared protection system component are not two independent protection systems, because both protection systems will be mutually impacted for a failure of a single shared component. A protection system component evaluation would include the evaluation of the consequences on system performance for the failure of any protection system component that is integral to the operation of the protection system being evaluated and to the operation of another protection system.

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Question 2: For the phrase “Delayed Clearing⁵” used in Category C⁶ contingencies 6-9 and Category D⁷ contingencies 1-4, to what extent does the description in Table 1, footnote (e)⁸ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

There is a lack of clarity whether footnote (e) in Table 1 requires the study and/or simulation of a failure of a protection system component (i.e., single point of failure) that may prevent correct operation of the protection system(s) impacted by the component failure. Protection systems that share a protection system component are fully dependent upon the correct operation of that single shared component and do not perform as two independent protection systems. This lack of clarity may result in a potential reliability gap.

Clarity is necessary as to whether (1) a valid assessment should include evaluation of delayed clearing due to failure of the protection system component (i.e., single point of failure), such as the failure of a shared protection system component, that produces the more severe system results or impacts; and (2) the study and/or simulation of the fault clearing sequence and protection system(s) operation should be based on the protection system(s) as-built design.

The lack of clarity is compounded by the similarity between the phrase “Delayed Clearing” used in TPL-003-0a and TPL-004-0, footnote (e), and the NERC glossary term “Delayed Fault Clearing.” While TPL-003-0a and TPL-004-0 do not use the glossary term, the similarity may lead to confusion and inconsistency in how entities apply footnote (e) to “stuck breaker” or “protection system failure” contingency assessments.

Question 1

For the parenthetical “(stuck breaker or protection system failure)” in TPL-003-0a (Category C contingencies 6-9) and TPL-004-0 (Category D contingencies 1-4), does an entity have the option of evaluating the effects⁹ of either “stuck breaker” or “protection system failure” contingency¹⁰, or does an applicable entity have to evaluate the contingency that produces the more severe system results or impacts as identified in R1.3.1 of both standards?

Response 1

⁵ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

⁶ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

⁷ As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

⁸ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

⁹ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.3.10. and/or TPL-004-0, Requirement R1.3.7.

¹⁰ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

The interpretation drafting team concludes that the Planning Authority and Transmission Planner must evaluate the situation that produces the more severe system results or impacts (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1) due to a delayed clearing condition regardless of whether the condition resulted from a stuck breaker or protection system failure. The Reliability Standards TPL-003-0a (Table I, Category C contingencies 6-9) and TPL-004-0 (Table I, Category D contingencies 1-4) involve an assessment of the effects of either a stuck breaker or a protection system failure. The single line ground (SLG) (TPL-003-0a, Table I, Category C) Fault and 3-phase (3 ϕ) (TPL-004-0, Table I, Category D) Fault contingencies with delayed clearing are further defined by footnote (e) and the parenthetical phrase “(stuck breaker or protection system failure).” Footnote (e) explains that “Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.” The parenthetical further emphasizes that the failure may be a “stuck breaker or protection system failure” that causes the delayed clearing of the fault. The text in Table 1 in either standard explains that when selecting delayed clearing contingencies to evaluate, both conditions “(stuck breaker or protection system failure)” must be considered.

Question 2

For the phrase “Delayed Clearing¹¹” used in Category C¹² contingencies 6-9 and Category D¹³ contingencies 1-4, to what extent does the description in Table 1, footnote (e)¹⁴ require an entity to model a single point of failure of a protection system component that may prevent correct operation of a protection system, including other protection systems impacted by that failed component based on the as-built design of that protection system?

Response 2

The term “Delayed Clearing” that is described in Table I, footnote (e) refers to fault clearing that results from a failure to achieve the protection system’s normally expected clearing time. For Category C or D contingencies, each Planning Authority and Transmission Planner is permitted engineering judgment in its selection of the protection system component failures for evaluation that would produce the more severe system results or impact (i.e., TPL-003-0a, R1.3.1 and TPL-004-0, R1.3.1). The evaluation would include addressing all protection systems affected by the selected component.

A protection system component failure that impacts one or more protection systems and increases the total fault clearing time requires the Planning Authority and Transmission Planner to simulate the full impact (clearing time and facilities removed) on the Bulk Electric System performance.

¹¹ As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5. and/or TPL-004-0, Requirement R1.4.

¹² As required by NERC Reliability Standard TPL-003-0a, Requirement R1.5.

¹³ As required by NERC Reliability Standard TPL-004-0, Requirement R1.4.

¹⁴ Footnote (e) Delayed Clearing: “failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay,”

Standard TPL-004-0a(x) — System Performance Following Extreme BES Events

The interpretation drafting team bases this conclusion on the footnote (e) example “...any protection system component such as, relay, circuit breaker, or current transformer...” because the component “circuit breaker” is not addressed in the current or previously defined NERC glossary term. The interpretation drafting team initially believed the lowercase usage of “protection system” inferred the NERC glossary term and the components described therein; however, based on the interpretation drafting team’s further assessment of footnote (e), it concludes that the existing TPL standards (TPL-003-0a and TPL-004-0) do not implicitly use the NERC glossary term. Without an explicit reference to the NERC glossary term, “Protection System,” the two standards do not prescribe the specific protection system components that must be addressed by the Planning Authority and Transmission Planner in performing the studies required in TPL-003-0a and TPL-004-0.