

**NORMES DE FIABILITÉ DE LA NERC
(VERSION ANGLAISE)**

A. Introduction

1. **Title:** Facility Interconnection Requirements
2. **Number:** FAC-001-2
3. **Purpose:** To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Transmission Owner
 - 4.1.2 Applicable Generator Owner
 - 4.1.2.1 Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system.
5. **Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is one year after the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is one year after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

- R1.** Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
 - 1.1. generation Facilities;
 - 1.2. transmission Facilities; and
 - 1.3. end-user Facilities.
- M1.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R1.
- R2.** Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is

used to interconnect to the Transmission system. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

- M2.** Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements) that it met all requirements in Requirement R2.
- R3.** Each Transmission Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*
 - 3.1.** Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s).
 - 3.2.** Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.
- M3.** Each Transmission Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R3.
- R4.** Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: *[Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*
 - 4.1.** Procedures for coordinated studies of new interconnections and their impacts on affected system(s).
 - 4.2.** Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.
- M4.** Each applicable Generator Owner shall have evidence (such as dated, documented Facility interconnection requirements addressing the procedures) that it met all requirements in Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) 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 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 Transmission Owner and applicable Generator Owner 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 responsible entities shall retain documentation as evidence for three 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 Check

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	Lower	N/A	<p>The Transmission Owner documented Facility interconnection requirements and updated them as needed, but failed to make them available upon request.</p> <p>OR</p> <p>The Transmission Owner documented Facility interconnection requirements and made them available upon request, but failed to update them as needed.</p> <p>OR</p> <p>The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but</p>	<p>The Transmission Owner documented Facility interconnection requirements, but failed to update them as needed and failed to make them available upon request.</p> <p>OR</p> <p>The Transmission Owner documented Facility interconnection requirements, updated them as needed, and made them available upon request, but failed to address interconnection requirements for two of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.</p>	<p>The Transmission Owner did not document Facility interconnection requirements.</p>

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				failed to address interconnection requirements for one of the Facilities as specified in R1, Parts 1.1, 1.2, or 1.3.		
R2	Long-term Planning	Lower	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 45 calendar days but less than or equal to 60 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 60 calendar days but less than or equal to 70 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 70 calendar days but less than or equal to 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.	The applicable Generator Owner failed to document Facility interconnection requirements and make them available upon request until more than 80 calendar days after full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the Transmission system.

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R3	Long-term Planning	Lower	N/A	N/A	The Transmission Owner addressed either R3, Part 3.1 or Part 3.2 in its Facility interconnection requirements, but did not address both.	The Transmission Owner addressed neither R3, Part 3.1 nor Part 3.2 in its Facility interconnection requirements.
R4	Long-term Planning	Lower	N/A	N/A	The applicable Generator Owner addressed either R4, Part 4.1 or Part 4.2 in its Facility interconnection requirements, but did not address both.	The applicable Generator Owner addressed neither R4, Part 4.1 nor Part 4.2 in its Facility interconnection requirements.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.

Requirement R3:

Originally the Parts of R3, with the exception of the first two bullets, which were added by the Project 2010-02 drafting team, this list has been moved to the Guidelines and Technical Basis section to provide entities with the flexibility to determine the Facility interconnection requirements that are technically appropriate for their respective Facilities. Including them as Parts of R3 was deemed too prescriptive, as frequently some items in the list do not apply to all applicable entities – and some applicable entities will have requirements that are not included in this list.

Each Transmission Owner and applicable Generator Owner should consider the following items in the development of Facility interconnection requirements:

- Procedures for requesting a new Facility interconnection or material modification to an existing interconnection
- Data required to properly study the interconnection
- Voltage level and MW and MVAR capacity or demand at the point of interconnection
- Breaker duty and surge protection
- System protection and coordination
- Metering and telecommunications
- Grounding and safety issues
- Insulation and insulation coordination
- Voltage, Reactive Power (including specifications for minimum static and dynamic reactive power requirements), and power factor control
- Power quality impacts
- Equipment ratings
- Synchronizing of Facilities
- Maintenance coordination
- Operational issues (abnormal frequency and voltages)
- Inspection requirements for new or materially modified existing interconnections
- Communications and procedures during normal and emergency operating conditions

Application Guidelines

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1		Added requirements for Generator Owner and brought overall standard format up to date.	Revision under Project 2010-07
1	February 9, 2012	Adopted by the Board of Trustees	
1	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-001-1. This standard became enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	
2		Revisions to implement the recommendations of the FAC Five-Year Review Team.	Revision under Project 2010-02
2	August 14, 2014	Adopted by the Board of Trustees	
2	November 6, 2014	FERC letter order issued approving FAC-001-2.	

Standard FAC-001-2 — Facility Interconnection Requirements

Appendix QC-FAC-001-2 Provisions specific to the standard FAC-001-2 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** Facility Interconnection Requirements
2. **Number:** FAC-001-2
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Effective Date:**
 - 5.1. Adoption of the standard by the Régie: Month xx, 201x
 - 5.2. Adoption of the appendix by the Régie: Month xx, 201x
 - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

B. Requirements and Measures

No specific provision

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

Table of compliance elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Standard FAC-001-2 — Facility Interconnection Requirements

Appendix QC-FAC-001-2

Provisions specific to the standard FAC-001-2 applicable in Québec

Revision history

Revision	Adoption Date	Action	Change Tracking
0	Month xx, 201x	New appendix	New

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-3
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability**
 - 4.1. Transmission Owner.
 - 4.2. Generator Owner.
5. **Effective Date:** The first day of the first calendar quarter that is twelve months beyond the date approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter twelve months following BOT adoption.

B. Requirements

- R1. Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
 - 1.1. The documentation shall contain assumptions used to rate the generator and at least one of the following:
 - Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
 - Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.
 - 1.2. The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- R2. Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
 - 2.1. The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:
 - Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.

- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
 - A practice that has been verified by testing, performance history or engineering analysis.
- 2.2.** The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:
- 2.2.1.** Equipment Rating standard(s) used in development of this methodology.
 - 2.2.2.** Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.
 - 2.2.3.** Ambient conditions (for particular or average conditions or as they vary in real-time).
 - 2.2.4.** Operating limitations.¹
- 2.3.** A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
- 2.4.** The process by which the Rating of equipment that comprises a Facility is determined.
- 2.4.1.** The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.
 - 2.4.2.** The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.
- R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following:
[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]
- 3.1.** The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:
- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
 - One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
 - A practice that has been verified by testing, performance history or engineering analysis.
- 3.2.** The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:
- 3.2.1.** Equipment Rating standard(s) used in development of this methodology.

¹ Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

- 3.2.2. Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.
 - 3.2.3. Ambient conditions (for particular or average conditions or as they vary in real-time).
 - 3.2.4. Operating limitations.²
 - 3.3. A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.
 - 3.4. The process by which the Rating of equipment that comprises a Facility is determined.
 - 3.4.1. The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.
 - 3.4.2. The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.
- R4. Each Transmission Owner shall make its Facility Ratings methodology and each Generator Owner shall each make its documentation for determining its Facility Ratings and its Facility Ratings methodology available for inspection and technical review by those Reliability Coordinators, Transmission Operators, Transmission Planners and Planning Coordinators that have responsibility for the area in which the associated Facilities are located, within 21 calendar days of receipt of a request. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)
- R5. If a Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's Facility Ratings methodology or Generator Owner's documentation for determining its Facility Ratings and its Facility Rating methodology, the Transmission Owner or Generator Owner shall provide a response to that commenting entity within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the Facility Ratings methodology and, if no change will be made to that Facility Ratings methodology, the reason why. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]* (Retirement approved by FERC effective January 21, 2014.)
- R6. Each Transmission Owner and Generator Owner shall have Facility Ratings for its solely and jointly owned Facilities that are consistent with the associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R7. Each Generator Owner shall provide Facility Ratings (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) as scheduled by such requesting entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R8. Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s),

² Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- 8.1.** As scheduled by the requesting entities:
 - 8.1.1.** Facility Ratings
 - 8.1.2.** Identity of the most limiting equipment of the Facilities
- 8.2.** Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:
 - 8.2.1.** Identity of the existing next most limiting equipment of the Facility
 - 8.2.2.** The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

C. Measures

- M1.** Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.
- M2.** Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.
- M3.** Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.
- M4.** Each Transmission Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement 4. The Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it made its documentation for determining its Facility Ratings or its Facility Ratings methodology available for inspection within 21 calendar days of a request in accordance with Requirement R4. (Retirement approved by NERC BOT pending applicable regulatory approval.)
- M5.** If the Reliability Coordinator, Transmission Operator, Transmission Planner or Planning Coordinator provides documented comments on its technical review of a Transmission Owner's or Generator Owner's Facility Ratings methodology or a Generator Owner's documentation for determining its Facility Ratings, the Transmission Owner or Generator Owner shall have evidence, (such as a copy of a dated electronic or hard copy note, or other comparable evidence from the Transmission Owner or Generator Owner addressed to the commenter that includes the response to the comment,) that it provided a response to that commenting entity in accordance with Requirement R5. (Retirement approved by NERC BOT pending applicable regulatory approval.)
- M6.** Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings are consistent with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3 (Requirement R6).
- M7.** Each Generator Owner shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings to its associated Reliability

Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R7.

- M8.** Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Enforcement Processes:

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

1.3. Data Retention

The Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.

The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.

The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.

The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.

The Generator Owner and Transmission Owner shall each keep evidence for Measure M4, and Measure M5, for three calendar years. (Retirement approved by FERC effective January 21, 2014.)

The Generator Owner shall keep evidence for Measure M7 for three calendar years.

The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.

If a Generator Owner or Transmission Owner 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 and all subsequent compliance records.

1.4. Additional Compliance Information

None

Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	<ul style="list-style-type: none"> • The Generator Owner’s Facility Rating documentation did not address Requirement R1, Part 1.1. 	The Generator Owner’s Facility Rating documentation did not address Requirement R1, Part 1.2.	The Generator Owner failed to provide documentation for determining its Facility Ratings.
R2	<p>The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4 	<p>The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4 	<p>The Generator Owner’s Facility Rating methodology did not address all the components of Requirement R2, Part 2.4.</p> <p>OR</p> <p>The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> • 2.1. • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4 	<p>The Generator Owner’s Facility Rating methodology failed to recognize a facility’s rating based on the most limiting component rating as required in Requirement R2, Part 2.3</p> <p>OR</p> <p>The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2:</p> <ul style="list-style-type: none"> • 2.1 • 2.2.1 • 2.2.2 • 2.2.3 • 2.2.4
R3	<p>The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> • 3.1 • 3.2.1 	<p>The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> • 3.1 • 3.2.1 	<p>The Transmission Owner’s Facility Rating methodology did not address either of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> • 3.4.1 • 3.4.2 	<p>The Transmission Owner’s Facility Rating methodology failed to recognize a Facility’s rating based on the most limiting component rating as required in Requirement R3, Part 3.3</p> <p>OR</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<ul style="list-style-type: none"> • 3.2.2 • 3.2.3 • 3.2.4 	<ul style="list-style-type: none"> • 3.2.2 • 3.2.3 • 3.2.4 	<p>OR</p> <p>The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4 	<p>The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3:</p> <ul style="list-style-type: none"> • 3.1 • 3.2.1 • 3.2.2 • 3.2.3 • 3.2.4
<p>R4</p> <p>(Retirement approved by FERC effective January 21, 2014.)</p>	<p>The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 21 calendar days but less than or equal to 31 calendar days after a request.</p>	<p>The responsible entity made its Facility Ratings methodology or Facility Ratings documentation available within more than 31 calendar days but less than or equal to 41 calendar days after a request.</p>	<p>The responsible entity made its Facility Rating methodology or Facility Ratings documentation available within more than 41 calendar days but less than or equal to 51 calendar days after a request.</p>	<p>The responsible entity failed to make its Facility Ratings methodology or Facility Ratings documentation available in more than 51 calendar days after a request. (R3)</p>
<p>R5</p> <p>(Retirement approved by FERC effective January 21, 2014.)</p>	<p>The responsible entity provided a response in more than 45 calendar days but less than or equal to 60 calendar days after a request. (R5)</p>	<p>The responsible entity provided a response in more than 60 calendar days but less than or equal to 70 calendar days after a request.</p> <p>OR</p> <p>The responsible entity provided a response within 45 calendar days, and the response indicated that a change will not be made to the Facility Ratings methodology or Facility Ratings documentation but did not indicate why no change will be made. (R5)</p>	<p>The responsible entity provided a response in more than 70 calendar days but less than or equal to 80 calendar days after a request.</p> <p>OR</p> <p>The responsible entity provided a response within 45 calendar days, but the response did not indicate whether a change will be made to the Facility Ratings methodology or Facility Ratings documentation. (R5)</p>	<p>The responsible entity failed to provide a response as required in more than 80 calendar days after the comments were received. (R5)</p>

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for 5% or less of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 5% or more, but less than up to (and including) 10% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 10% up to (and including) 15% of its solely owned and jointly owned Facilities. (R6)	The responsible entity failed to establish Facility Ratings consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings for more than 15% of its solely owned and jointly owned Facilities. (R6)
R7	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days.	The Generator Owner provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. OR The Generator Owner failed to provide its Facility Ratings to the requesting entities.
R8	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but the information	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 90%, but not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR	The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1) OR The responsible entity provided less than 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1) OR The responsible entity provided the required Rating information to the requesting entity, but did so more

Standard FAC-008-3 — Facility Ratings

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>was provided up to and including 15 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2)</p>	<p>The responsible entity provided the required Rating information to the requesting entity, but did so more than 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2)</p>	<p>The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2)</p>	<p>than 35 calendar days late. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2)</p> <p>OR</p> <p>The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1)</p>

E. Regional Variances

None.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	Feb 7, 2006	Approved by Board of Trustees	New
1	Mar 16, 2007	Approved by FERC	New
2	May 12, 2010	Approved by Board of Trustees	Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693
3	May 24, 2011	Addition of Requirement R8	Project 2009-06 Expansion to address third directive from Order 693
3	May 24, 2011	Adopted by NERC Board of Trustees	
3	November 17, 2011	FERC Order issued approving FAC-008-3	
3	May 17, 2012	FERC Order issued directing the VRF for Requirement R2 be changed from “Lower” to “Medium”	
3	February 7, 2013	R4 and 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.	
3	November 21, 2013	R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Standard FAC-008-3 — Facility Ratings

Appendix QC-FAC-008-3 Provisions specific to the standard FAC-008-3 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** Facility Ratings
2. **Number:** FAC-008-3
3. **Purpose:** No specific provision
4. **Applicability:**
 - Functions**
No specific provision
 - Facilities**
This standard only applies to the facilities of the Main Transmission System (RTP)
5. **Effective Date:**
 - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x
 - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x
 - 5.3. Effective date of the standard and its appendix in Québec: Month xx 201x

B. Requirements

No specific provision

C. Measures

No specific provision

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Enforcement Authority**

The Régie de l'énergie is responsible, in Québec, for compliance enforcement with respect to the reliability standard and its appendix that it adopts.
 - 1.2. **Compliance Monitoring and Enforcement Processes**

No specific provision
 - 1.3. **Data Retention**

No specific provision
 - 1.4. **Additional Compliance Information**

No specific provision
2. **Violation Severity Levels**

No specific provision

Standard FAC-008-3 — Facility Ratings

Appendix QC-FAC-008-3 Provisions specific to the standard FAC-008-3 applicable in Québec

E. Regional Differences

No specific provision

F. Associated Documents

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Month xx, 201x	New appendix	New

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
2. **Number:** MOD-025-2
3. **Purpose:** To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

4. **Applicability:**

- 4.1. Functional entities

- 4.1.1 Generator Owner

- 4.1.2 Transmission Owner that owns synchronous condenser(s)

- 4.2. Facilities:

For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following:

- 4.2.1 Individual generating unit greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- 4.2.2 Synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

- 4.2.3 Generating plant/Facility greater than 75 MVA (gross aggregate nameplate rating) directly connected to the Bulk Electric System.

5. **Effective Date:**

- 5.1. In those jurisdictions where regulatory approval is required¹:

- 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 and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

- 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 and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

- 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

¹ Wind Farm Verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

the laws applicable to such ERO governmental authorities, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

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 and Transmission Owner shall have verified 100 percent of its applicable Facilities.

5.2. In those jurisdictions where regulatory approval is not required²:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 40 percent of its applicable Facilities.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 60 percent of its applicable Facilities.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified at least 80 percent of its applicable Facilities.

5.2.4 By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner and Transmission Owner shall have verified 100 percent of its applicable Facilities.

Note: The verification percentage above is based on the number of applicable units owned.

² Wind farm verification - If an entity has two wind sites, and verification of one site is complete, the entity is 50% complete regardless of the number of turbines at each site. A wind site is a group of wind turbines connected at a common point of interconnection or utilizing a common aggregate control system.

Requirements

- R1.** Each Generator Owner shall provide its Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 1.1.** Verify the Real Power capability of its generating units in accordance with Attachment 1.
 - 1.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.
- R2.** Each Generator Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 2.1.** Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units and (ii) the Reactive Power capability of its synchronous condenser units.
 - 2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.
- R3.** Each Transmission Owner shall provide its Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 3.1.** Verify, in accordance with Attachment 1, the Reactive Power capability of its synchronous condenser units.
 - 3.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to its Transmission Planner within 90 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

B. Measures

- M1.** Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1.
- M2.** Each Generator Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2.

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

- M3.** Each Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Transmission Owner form with equivalent information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 90 days to its Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance enforcement authority 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 a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance 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 and Transmission Owner shall each keep the 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 Generator Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest MOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirement R3, Measure M3 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time 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

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<p>The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing 1 to less than or equal to 33 percent of the data.</p>	<p>The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing more than 33 to 66 percent of the data.</p>	<p>The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner verified the Real Power capability, per Attachment 1 and submitted the data but was missing from 67 to 99 percent of the data.</p> <p>OR</p>	<p>The Generator Owner verified and recorded the Real Power capability of its applicable generating unit, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner failed to verify the Real Power capability, per Attachment 1 of an applicable generating unit.</p> <p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item</p>

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

	<p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.</p> <p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.</p>	<p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.</p> <p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.</p>	<p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.</p> <p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.</p>	<p>1 or item 2 (5 year requirement) but did so in more than 75 calendar months.</p> <p>OR</p> <p>The Generator Owner performed the Real Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.</p>
R2	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the	The Generator Owner verified and recorded the Reactive	The Generator Owner verified and recorded the Reactive Power

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

<p>Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per</p>	<p>Reactive Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120 calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2</p>	<p>Power capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 150 calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72</p>	<p>capability of its applicable generating unit or applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Generator Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable generating unit or synchronous condenser unit.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.</p> <p>OR</p>
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Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

	<p>Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less than or equal to 69 months.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.</p>	<p>(5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.</p>	<p>calendar months but less than or equal to 75 months.</p> <p>OR</p> <p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.</p>	<p>The Generator Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15 calendar months.</p>
R3	<p>The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more</p>	<p>The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 120</p>	<p>The Transmission Owner verified and recorded the Reactive Power capability of an applicable synchronous condenser unit, but submitted the data to its Transmission Planner more than 150</p>	<p>The Transmission Owner verified and recorded the Reactive Power capability of its applicable synchronous condenser, but submitted the data to its Transmission Planner more than 180 calendar days of the date the data is</p>

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

<p>than 90 calendar days, but within 120 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 1 to up to and including 33 percent of the data.</p> <p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 66 calendar months but less</p>	<p>calendar days, but within 150 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 34 to 66 percent of the data.</p> <p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 69 calendar months but less than or equal to 72 months.</p>	<p>calendar days, but within 180 calendar days, of the date the data is recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Transmission Owner verified the Reactive Power capability, per Attachment 1 and submitted the data but was missing 67 to 99 percent of the data.</p> <p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 72 calendar months but less than or equal to 75 months.</p>	<p>recorded for a staged test or the date the data is selected for verification using historical operational data.</p> <p>OR</p> <p>The Transmission Owner failed to verify the Reactive Power capability, per Attachment 1 of an applicable synchronous condenser unit.</p> <p>OR</p> <p>The Transmission Owner performed the verification per Attachment 1, “Periodicity for conducting a new verification” item 1 or item 2 (5 year requirement) but did so in more than 75 calendar months.</p> <p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 15calendar months.</p>
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Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

	<p>than or equal to 69 months.</p> <p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 12 calendar months but less than or equal to 13 calendar months.</p>	<p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 13 calendar months but less than or equal to 14 calendar months.</p>	<p>OR</p> <p>The Transmission Owner performed the Reactive Power verification per Attachment 1, “Periodicity for conducting a new verification” item 1, 2 or 3 (12 calendar month requirement) but did so in more than 14 calendar months but less than or equal to 15 calendar months.</p>	
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Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

D. Regional Variances

None

E. Associated Documents

Version History

Version	Date	Action	Change Tracking
1	12/1/2005	<ol style="list-style-type: none"> 1. Changed tabs in footer. 2. Removed comma after 2004 in “Development Steps Completed,” #1. 3. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 4. Added “periods” to items where appropriate. 5. Changed apostrophes to “smart” symbols. 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all instances of “regional” in section D.3. 8. Removed the word “less” after 94% in section 3.4. Level 4. 	01/20/06
2	February 7, 2013	Adopted by NERC Board of Trustees	Revised per SAR for Project 2007-09 and combined with MOD-024-1
2	March 20, 2014	FERC Order issued approving MOD-025-2. (Order becomes effective on 7/1/16.)	

MOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conducting a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months. The first verification for each applicable Facility under this standard must be a staged test.
2. For verification using operational data; verify each applicable Facility at least every five years (with no more than 66 calendar months between verifications), or within 12 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. If data for different points is recorded on different days, designate the earliest of those dates as the verification date, and report that date as the verification date on MOD-025, Attachment 2 for periodicity purposes.
3. For either verification method, verify each new applicable Facility within 12 calendar months of its commercial operation date. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 12 calendar months.

It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below.

If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Verification specifications for applicable Facilities:

1. For generating units of 20 MVA or less that are part of a plant greater than 75 MVA in aggregate, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 20 MVA (gross nameplate rating).
2. Verify with all auxiliary equipment needed for expected normal operation in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

verification. Operational data from within the two years prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:

- 2.1.** Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.
 - 2.1.1** Verify synchronous generating unit's maximum real power and lagging reactive power for a minimum of one hour.
 - 2.1.2** Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.
- 2.2.** Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:
 - 2.2.1** At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached.
 - 2.2.2** At maximum Real Power output collect maximum leading reactive values as soon as a limit is reached.
 - 2.2.3** Nuclear Units are not required to perform Reactive Power verification at minimum Real Power output.
- 2.3.** For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.
- 2.4.** Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU

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transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.

3. Record the following data for the verifications specified above:
 - 3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.
 - 3.2. The voltage schedule provided by the Transmission Operator, if applicable.
 - 3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.
 - 3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:
 - Ambient air temperature
 - Relative humidity
 - Cooling water temperature
 - Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.
 - 3.5. The date and time of the verification period, including start and end time in hours and minutes.
 - 3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.
 - 3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.
 - 3.8. Whether the test data is a result of a staged test or if it is operational data.
4. Develop a simplified key one-line diagram (refer to MOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.
 - 4.1. If metering does not exist to measure specific Reactive auxiliary load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.
5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 90 days of the request or the date the data was recorded/selected whichever is later.

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- Note 1: Under some transmission system conditions, the data points obtained by the Mvar verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve). However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The Mvar limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.
- Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve), it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.
- Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.
- Note 4: Synchronous Condensers only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

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MOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in MOD-025, Attachment 1) is reported.

Company:

Reported By (name):

Plant:

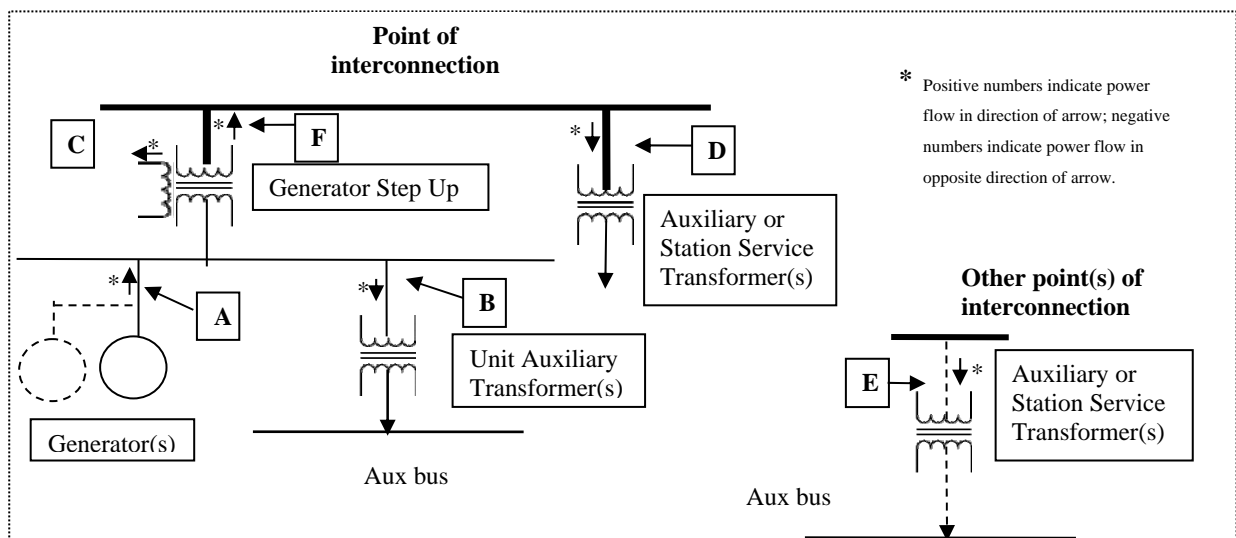
Unit No.:

Date of Report:

Check all that apply:

- Over-excited Full Load Reactive Power Verification
- Under-excited Full Load Reactive Power Verification
- Over-excited Minimum Load Reactive Power Verification
- Under-excited Minimum Load Reactive Power Verification
- Real Power Verification
- Staged Test Data
- Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



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Point	Voltage	Real Power	Reactive Power	Comment
A	kV	MW	Mvar	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 20 MVA.
Identify calculated values, if any:				
B	kV	MW	Mvar	Sum multiple unit auxiliary transformers.
Identify calculated values, if any:				
C	kV	MW	Mvar	Sum multiple tertiary Loads, if any.
Identify calculated values, if any:				
D	kV	MW	Mvar	Sum multiple auxiliary and station service transformers.
Identify calculated values, if any:				
E	kV	MW	Mvar	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	kV	MW	Mvar	Net unit capability
Identify calculated values, if any:				

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MOD-025 -Attachment 2 (continued)

Verification Data

Provide data by unit or Facility, as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus(*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _____, Verification Start Time _____, Verification End Time _____
- Scheduled Voltage _____
- Transformer Voltage Ratio: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end of the verification period:
 - Air temperature: _____
 - Humidity: _____
 - Cooling water temperature: _____
 - Other data as applicable: _____

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- Generator hydrogen pressure at time of test (if applicable) _____

Date that data shown in last verification column in table above was taken _____

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Appendix QC-MOD-025-2 Provisions specific to the standard MOD-025-2 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability
2. **Number:** MOD-025-2
3. **Purpose:** No specific provision
4. **Applicability:**
 - 4.1. **Functional entities**
No specific provision
 - 4.2. **Facilities**
 - 4.2.1 Generating unit that is part of the Main Transmission System (RTP).
 - 4.2.2 Synchronous condenser that is part of the Main Transmission System (RTP).
 - 4.2.3 Generating plant/Facility that is part of the Main Transmission System (RTP).
5. **Effective Date:**
 - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx, 201x
 - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx, 201x
 - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

Requirements

No specific provision

B. Measures

No specific provision

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

4.2. For the purpose of this standard, the term, “applicable Facility” shall mean any one of the following;

Mis en forme : Anglais (Canada)

Mis en forme : Retrait : Gauche :
2,54 cm, Sans numérotation ni puces

Mis en forme : Anglais (Canada)

Mis en forme : Police :Non Gras

Standard MOD-025-2 — Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Appendix QC-MOD-025-2
Provisions specific to the standard MOD-025-2 applicable in Québec

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

D. Regional Variances

No specific provision

E. Associated Documents

No specific provision

MOD-025-2 – Attachment 1

No specific provision

MOD-025-2 – Attachment 2

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	Month xx, 201x	New appendix	New

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
2. **Number:** MOD-026-1
3. **Purpose:** To verify that the generator excitation control system or plant volt/var control function¹ model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

4. **Applicability:**

4.1. Functional Entities:

- 4.1.1 Generator Owner
- 4.1.2 Transmission Planner

4.2. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an “applicable unit” that meet the following:

- 4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:
 - 4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).
 - 4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).
- 4.2.2 Generation in the Western Interconnection with the following characteristics:
 - 4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).
 - 4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

¹ Excitation control system or plant volt/var control function:

- a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and power system stabilizer.
- b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 For all Interconnections:

- A technically justified² unit that meets NERC registry criteria but is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and is requested by the Transmission Planner.

5. Effective Date:

5.1. For Requirements R1, and R3 through R6, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter 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.

5.2. For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.3. For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

5.4. For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years

² Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

- R1.** Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request : *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
 - Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
 - Model data for any of the Generator Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.
- R2.** Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 2.1.** Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s), or both. Each verification shall include the following:
- 2.1.1.** Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,
 - 2.1.2.** Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed),
 - 2.1.3.** Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

- 2.1.4. Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,
 - 2.1.5. Compensation settings (such as droop, line drop, differential compensation), if used, and
 - 2.1.6. Model structure and data for power system stabilizer, if so equipped.
- R3.** Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit:
- Written notification from its Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
 - Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
 - Written comments and supporting evidence from its Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification³ (in accordance with Requirement R2). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- R4.** Each Generator Owner shall provide revised model data or plans to perform model verification⁴ (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the excitation control system or plant volt/var control function that alter the equipment response characteristic.⁵ [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

³ If verification is performed, the 10-year period as outlined in MOD-026 Attachment 1 is reset.

⁴ Ibid

⁵ Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

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- R5.** Each Generator Owner shall provide a written response to its Transmission Planner, within 90 calendar days following receipt of a technically justified⁶ unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- Details of plans to verify the model (in accordance with Requirement R2), or
 - Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.
- R6.** Each Transmission Planner shall provide a written response to the Generator Owner within 90 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 6.1 through 6.3) or is not usable.
- 6.1.** The excitation control system or plant volt/var control function model initializes to compute modeling data without error,
- 6.2.** A no-disturbance simulation results in negligible transients, and
- 6.3.** For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

C. Measures

- M1.** The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.
- M2.** The Generator Owner must have and provide dated evidence it verified each generator excitation control system or plant volt/var control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.
- M3.** Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence

⁶ Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

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of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.

- M4.** Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 180 calendar days of making changes.
- M5.** Evidence for Requirement R5 must include the Generator Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 90 calendar days following receipt of a technically justified request.
- M6.** Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority 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 and Transmission Planner 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:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.

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- The Generator Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time 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

Complaints

1.4. Additional Compliance Information

None

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2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	<p>The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner after the timeframe specified in MOD-026 Attachment 1 but less than or equal to 90 calendar days late;</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner verified models that omitted one of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.</p>	<p>The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1.</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner verified models that omitted two of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.</p>	<p>The Generator Owner provided its verified model(s), including documentation and data to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-026 Attachment 1.</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner verified models that omitted three of the six Parts identified in Requirement R2, Parts 2.1.1 through 2.1.6.</p>	<p>The Generator Owner provided its verified model(s), including documentation and data more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-026 Attachment 1.</p> <p>OR</p> <p>The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1.</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner verified model(s) but omitted four or more of the six parts identified in Requirement R2, Subparts 2.1.1 through 2.1.6.</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice. OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the excitation control system or plant volt/var control function that altered the equipment response characteristic.
R5	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days to the Transmission Planner following receipt of a technically justified request to perform a model review of an applicable unit.	The Generator Owner failed to provide a written response to the Transmission Planner within 180 calendar days following receipt of a technically justified request to perform a model review of an applicable unit. OR The Generator Owner's written response failed to include one of the sub bullets of Requirement R5.

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6	<p>The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information.</p>	<p>The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information.</p> <p>OR</p> <p>The Transmission Planner’s written response omitted confirmation for one of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.</p>	<p>The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable; including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information.</p> <p>OR</p> <p>The Transmission Planner’s written response omitted confirmation for two of the specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.</p>	<p>The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information.</p> <p>OR</p> <p>The Transmission Planner’s written response omitted confirmation for all specified model criteria listed in Requirement R6, Parts 6.1 through 6.3.</p>

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving MOD-026-1. (Order becomes effective for R1, R3, R4, R5, and R6 on 7/1/14. R2 becomes effective on 7/1/18.)	

G. References

The following documents contain technical information beyond the scope of this Standard on excitation control system functionality, modeling, and testing.

1. IEEE 421.1 Definitions for Excitation Systems for Synchronous Machines
2. IEEE 421.2 Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems
3. IEEE 421.5 IEEE Recommended Practice for Excitation System Models for Power System Stability Studies
4. K. Clark, R.A. Walling, N.W. Miller, "Solar Photovoltaic (PV) Plant Models in PSLF," IEEE/PES General Meeting, Detroit, MI, July 2011
5. M. Asmine, J. Brochu, J. Fortmann, R. Gagnon, Y. Kazachkov, C.-E. Langlois, C. Larose, E. Muljadi, J. MacDowell, P. Pourbeik, S. A. Seman, and K. Wiens, "Model Validation for Wind Turbine Generator Models", IEEE Transactions on Power System, Volume 26, Issue 3, August 2011
6. A. Ellis, E. Muljadi, J. Sanchez-Gasca, Y. Kazachkov, "Generic Models for Simulation of Wind Power Plants in Bulk System Planning Studies," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
7. N.W. Miller, J. J. Sanchez-Gasca, K. Clark, J.M. MacDowell, "Dynamic Modeling of GE Wind Plants for Stability Simulations," IEEE PES General Meeting 2011, Detroit, MI, July 24-28
8. A. Ellis, Y. Kazachkov, E. Muljadi, P. Pourbeik, J.J. Sanchez-Gasca, Working Group Joint Report – WECC Working Group on Dynamic Performance of Wind Power Generation & IEEE Working Group on Dynamic Performance of Wind Power Generation, "Description and Technical Specifications for Generic WTG Models – A Status Report," Proc. IEEE PES 2011 Power Systems Conference and Exposition (PSCE), March 2011, Phoenix, AZ
9. K. Clark, N.W. Miller, R.A. Walling, "Modeling of GE Solar Photovoltaic (PV) Plants for Grid Studies," version 1.1, April 2010
10. K. Clark, N.W. Miller, J. J. Sanchez-Gasca, "Modeling of GE Wind Turbine-Generators for Grid Studies," version 4.5, April 16, 2010, Available from GE Energy
11. R.J. Piwko, N.W. Miller, J.M. MacDowell, "Field Testing & Model Validation of Wind Plants," in Proc. IEEE PES General Meeting, Pittsburg, PA, July 2008
12. N. Miller, K. Clark, J. MacDowell and W. Barton, "Experience with Field and Factory Testing for Model Validation of GE Wind Plants," in Proc. Eur. Wind Energy Conf. Exhib., Brussels, Belgium, March/April 2008

13. IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, “Guidelines for Generator Stability Model Validation Testing,” IEEE PES General Meeting 2007, paper 07GM1307
14. W.W. Price and J. J. Sanchez-Gasca, “Simplified Wind Turbine Generator Aerodynamic Models for Transient Stability Studies,” in PROC IEEE PES 2006 Power Systems Conf. Expo. (PSCE), Atlanta, GA, October 1, 2006, p. 986-992
15. J.J. Sanchez-Gasca, R.J. Piwko, N. W. Miller, W. W. Price, “On the Integration of Wind Power Plants in Large Power Systems,” Proc. X Symposium of Specialists in Electric and Expansion Planning (SEPOPE), Florianopolis, Brazil, May 2006
16. N. W. Miller, J. J. Sanchez-Gasca, W. W. Price, R. W. Delmerico, “Dynamic Modeling of GE 1.5 and 3.6 MW Wind Turbine-Generators for Stability Simulations,” Proc. IEEE Power Engineering Society General Meeting, Toronto, Ontario, July 2003
17. P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

MOD-026 Attachment 1		
Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 10-year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 350 MVA. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 10-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.
5	The Generator Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

MOD-026 Attachment 1		
Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
6	<p>New or existing applicable unit does not include an active closed loop voltage or reactive power control function.</p> <p>(Requirement R2)</p>	<p>Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner.</p> <p>Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) only if active closed loop function is established.</p> <p>See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).</p>
7	<p>Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less.</p> <p>(Requirement R2)</p>	<p>Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner.</p> <p>At the end of this 10-year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired.</p> <p>For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.</p>

MOD-026 Attachment 1 Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
<p>NOTES:</p> <p>NOTE 1: Establishing the recurring 10-year unit verification period start date: The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification.</p> <p>NOTE 2: Consideration for early compliance: Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 10-year period from the actual transmittal date if either of the following applies:</p> <ul style="list-style-type: none"> • The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification. • The Generator Owner has an existing verified model that is compliant with the requirements of this standard. 		

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Appendix QC-MOD-026-1 Provisions specific to the standard MOD-026-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

2. **Number:** MOD-026-1

3. **Purpose:** No specific provision

4. **Applicability:**

4.1. **Functional entities**

No specific provision

4.2. **Facilities**

For the purpose of the requirements contained herein, Facilities that form part of the Main Transmission System (RTP) will be collectively referred as an “applicable unit” that meet the following:

4.2.1 No specific provision

4.2.1.1 No specific provision

4.2.1.2 Individual generating plant consisting of multiple generating units that is part of the Main Transmission System (RTP) with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 No specific provision

4.2.3 No specific provision

4.2.4 A technically justified¹ Main Transmission System (RTP) Facility that is not otherwise included in the above Applicability sections 4.2.1, 4.2.2, or 4.2.3 and that is requested by the Transmission Planner.~~No specific provision~~

5. **Effective Date:**

5.1. Adoption of the standard by the Régie de l'énergie: Month xx, 201x

5.2. Adoption of the appendix by the Régie de l'énergie: Month xx, 201x

5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

B. Requirements

No specific provision

C. Measures

¹ Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Appendix QC-MOD-026-1

Provisions specific to the standard MOD-026-1 applicable in Québec

No specific provision

Standard MOD-026-1 — Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

**Appendix QC-MOD-026-1
Provisions specific to the standard MOD-026-1 applicable in Québec**

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Variances

No specific provision

F. Associated Documents

No specific provision

G. References

No specific provision

MOD-026-1 – Attachment 1

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	xx/xx/201x	New appendix	New

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
2. **Number:** MOD-027-1
3. **Purpose:** To verify that the turbine/governor and load control or active power/frequency control¹ model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

4. **Applicability:**

4.1. Functional entities

4.1.1 Generator Owner

4.1.2 Transmission Planner

4.2. Facilities

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an “applicable unit” that meet the following:

4.2.1 Generation in the Eastern or Quebec Interconnections with the following characteristics:

4.2.1.1 Individual generating unit greater than 100 MVA (gross nameplate rating).

4.2.1.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 100 MVA (gross aggregate nameplate rating).

4.2.2 Generation in the Western Interconnection with the following characteristics:

4.2.2.1 Individual generating unit greater than 75 MVA (gross nameplate rating).

4.2.2.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.3 Generation in the ERCOT Interconnection with the following characteristics:

¹ Turbine/governor and load control or active power/frequency control:

- a. Turbine/governor and load control applies to conventional synchronous generation.
- b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

4.2.3.1 Individual generating unit greater than 50 MVA (gross nameplate rating).

4.2.3.2 Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

5. Effective Date:

- 5.1.** For Requirements R1, and R3 through R5, the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter 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.
- 5.2.** For Requirement R2, 30 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is four years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is four years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- 5.3.** For Requirement R2, 50 percent of the entity's applicable unit gross MVA for each Interconnection on first day of the first calendar quarter that is six years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is six years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.
- 5.4.** For Requirement R2, 100 percent of the entity's applicable unit gross MVA for each Interconnection on the first day of the first calendar quarter that is 10 years following applicable regulatory approval or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter that is 10 years following NERC Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

- R1.** Each Transmission Planner shall provide the following requested information to the Generator Owner within 90 calendar days of receiving a written request: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,
 - Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
 - Model data for any of the Generator Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.
- R2.** Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
- 2.1.** Each applicable unit's model shall be verified by the Generator Owner using one or more models acceptable to the Transmission Planner. Verification for individual units rated less than 20 MVA (gross nameplate rating) in a generating plant (per Section 4.2.1.2, 4.2.2.2, or 4.2.3.2) may be performed using either individual unit or aggregate unit model(s) or both. Each verification shall include the following:
- 2.1.1.** Documentation comparing the applicable unit's MW model response to the recorded MW response for either:
- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
 - A speed governor reference change with the applicable unit on-line, or
 - A partial load rejection test,²
- 2.1.2.** Type of governor and load control or active power control/frequency control³ equipment,

² Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply.

³ Turbine/governor and load control or active power/frequency control:

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- 2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer),
 - 2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control, and
 - 2.1.5. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response (including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.
- R3.** Each Generator Owner shall provide a written response to its Transmission Planner within 90 calendar days of receiving one of the following items for an applicable unit.
- Written notification, from its Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not “usable,”
 - Written comments from its Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
 - Written comments and supporting evidence from its Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification⁴ (in accordance with Requirement R2). [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- R4.** Each Generator Owner shall provide revised model data or plans to perform model verification⁵ (in accordance with Requirement R2) for an applicable unit to its Transmission Planner within 180 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic⁶. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

-
- a. Turbine/governor and load control applies to conventional synchronous generation.
 - b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

⁴ If verification is performed, the 10 year period as outlined in MOD-027 Attachment 1 is reset.

⁵ Ibid.

⁶ Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

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- R5.** Each Transmission Planner shall provide a written response to the Generator Owner within 90 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable.
- 5.1.** The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,
- 5.2.** A no-disturbance simulation results in negligible transients, and
- 5.3.** For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

C. Measures

- M1.** The Transmission Planner must have and provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 90 calendar days in accordance with Requirement R1.
- M2.** The Generator Owner must have and provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to its Transmission Planner, in accordance with Requirement R2.
- M3.** Evidence for Requirement R3 must include the Generator Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.
- M4.** Evidence for Requirement R4 must include, for each of the Generator Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 180 calendar days of making changes.
- M5.** Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description is the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner was notified within 90 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall serve as the Compliance Enforcement Authority 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 and Transmission Planner 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:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner or Transmission Planner 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 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

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2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner provided the instructions and data to the Generator Owner more than 90 calendar days but less than or equal to 120 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 120 calendar days but less than or equal to 150 calendar days of receiving a written request.	The Transmission Planner provided the instructions and data to the Generator Owner more than 150 calendar days but less than or equal to 180 calendar days of receiving a written request.	The Transmission Planner failed to provide the instructions and data to the Generator Owner within 180 calendar days of receiving a written request.
R2	<p>The Generator Owner provided its verified model(s) to its Transmission Planner after the periodicity timeframe specified in MOD-027 Attachment 1 but less than or equal to 90 calendar days late;</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner a verified model that omitted one of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.</p>	<p>The Generator Owner provided its verified model(s) to its Transmission Planner more than 90 calendar days but less than or equal to 180 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1;</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner a verified model that omitted two of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.</p>	<p>The Generator Owner provided its verified model(s) to its Transmission Planner more than 180 calendar days but less than or equal to 270 calendar days late as specified by the periodicity timeframe in MOD-027 Attachment 1;</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner verified models that omitted three of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.</p>	<p>The Generator Owner provided its verified model(s) more than 270 calendar days late to its Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1;</p> <p>OR</p> <p>The Generator Owner failed to use model(s) acceptable to the Transmission Planner as specified in Requirement R2, Part 2.1;</p> <p>OR</p> <p>The Generator Owner provided the Transmission Planner verified model(s) that omitted four or more of the five Parts identified in Requirement R2, Subparts 2.1.1, through 2.1.5.</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	The Generator Owner provided a written response more than 90 calendar days but less than or equal to 120 calendar days of receiving written notice.	The Generator Owner provided a written response more than 120 calendar days but less than or equal to 150 calendar days of receiving written notice.	The Generator Owner provided a written response more than 150 calendar days but less than or equal to 180 calendar days of receiving written notice.	The Generator Owner failed to provide a written response within 180 calendar days of receiving written notice; OR The Generator Owner's written response failed to contain either the technical basis for maintaining the current model, or a list of future model changes, or a plan to perform another model verification.
R4	The Generator Owner provided revised model data or plans to perform model verification more than 180 calendar days but less than or equal to 210 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 210 calendar days but less than or equal to 240 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner provided revised model data or plans to perform model verification more than 240 calendar days but less than or equal to 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic.	The Generator Owner failed to provide revised model data or failed to provide plans to perform model verification within 270 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that altered the equipment response characteristic.

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	<p>The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 90 calendar days but less than or equal to 120 calendar days of receiving verified model information;</p>	<p>The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 120 calendar days but less than or equal to 150 calendar days of receiving the verified model information;</p> <p>OR</p> <p>The Transmission Planner’s written response omitted confirmation for one of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.</p>	<p>The Transmission Planner provided a written response to the Generator Owner indicating whether the model is usable or not usable, including a technical description if the model is not usable, more than 150 calendar days but less than or equal to 180 calendar days of receiving the verified model information;</p> <p>OR</p> <p>The Transmission Planner’s written response omitted confirmation for two of the specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.</p>	<p>The Transmission Planner failed to provide a written response to the Generator Owner within 180 calendar days of receiving the verified model information;</p> <p>OR</p> <p>The Transmission Planner provided a written response without including confirmation of all specified model criteria listed in Requirement R5, Parts 5.1 through 5.3.</p>

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	February 7, 2013	Adopted by NERC Board of Trustees	New
1	March 20, 2014	FERC Order issued approving MOD-027-1. (Order becomes effective for R1, R3, R4, and R5 on 7/1/14. R2 becomes effective 7/1/18.)	

G. References

The following documents contain technical information beyond the scope of this Standard on turbine/governor and load control or active power/frequency control system functionality, modeling, and testing.

- 1) IEEE Task Force on Generator Model Validation Testing of the Power System Stability Subcommittee, "Guidelines for Generator Stability Model Validation Testing," IEEE PES General Meeting 2007, paper 07GM1307
- 2) L. Pereira "New Thermal Governor Model Development: Its Impact on Operation and Planning Studies on the Western Interconnection" IEEE POWER AND ENERGY MAGAZINE, MAY/JUNE 2005
- 3) D.M. Cabbell, S. Rueckert, B.A. Tuck, and M.C. Willis, "The New Thermal Governor Model Used in Operating and Planning Studies in WECC," in Proc. IEEE PES General Meeting, Denver, CO, 2004
- 4) S. Patterson, "Importance of Hydro Generation Response Resulting from the New Thermal Modeling-and Required Hydro Modeling Improvements," in Proc. IEEE PES General Meeting, Denver, CO, 2004
- 5) L. Pereira, D. Kosterev, D. Davies, and S. Patterson, "New Thermal Governor Model Selection and Validation in the WECC," IEEE Trans. Power Syst., vol. 19, no. 1, pp. 517-523, February 2004
- 6) L. Pereira, J. Undrill, D. Kosterev, D. Davies, and S. Patterson, "A New Thermal Governor Modeling Approach in the WECC," IEEE Trans. Power Syst., vol. 18, no. 2, pp. 819-829, May 2003

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

- 7) P. Pourbeik, C. Pink and R. Bisbee, “Power Plant Model Validation for Achieving Reliability Standard Requirements Based on Recorded On-Line Disturbance Data”, Proceedings of the IEEE PSCE, March, 2011

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MOD-027 Attachment 1 Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 10year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 10-year anniversary of the last transmittal (per Note 2).
3	Applicable unit is not subjected to a frequency excursion per Note 1 by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a systemdisturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit’s real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 365 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit’s real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the commissioning date.

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

MOD-027 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
5	<p>Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location;</p> <p>AND</p> <p>Each applicable unit has the same MVA nameplate rating;</p> <p>AND</p> <p>The nameplate rating is \leq 350 MVA;</p> <p>AND</p> <p>Each applicable unit has the same components and settings;</p> <p>AND</p> <p>The model for one of these equivalent applicable units has been verified.</p> <p>(Requirement R2)</p>	<p>Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit.</p> <p>Verify a different equivalent unit during each 10-year verification period.</p> <p>Applies to Row 1 when calculating generation fleet compliance during the 10-year implementation period.</p>
6	<p>The Generator Owner has submitted a verification plan.</p> <p>(Requirement R3 or R4)</p>	<p>Transmit the verified model, documentation and data to the Transmission Planner within 365 calendar days after the submittal of the verification plan.</p>

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

MOD-027 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
7	<p>Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.);</p> <p>OR</p> <p>Applicable unit either does not have an installed frequency control system or has a disabled frequency control system.</p> <p>(Requirement R2)</p>	<p>Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner.</p> <p>Perform verification per the periodicity specified in Row 4 for a “New Generating Unit” (or new equipment) only if responsive control mode operation for connected operations is established.</p>
8	<p>Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less.</p> <p>(Requirement R2)</p>	<p>Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner.</p> <p>At the end of this 10 calendar year timeframe, the current average three year net capacity factor (for years 8, 9, and 10) can be examined to determine if the capacity factor exemption can be declared for the next 10 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired.</p> <p>For the definition of net capacity factor, refer to Appendix F of the GADS Data Reporting Instructions on the NERC website.</p>

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

MOD-027 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
NOTES:		
<p>NOTE 1: Unit model verification frequency excursion criteria:</p> <ul style="list-style-type: none"> • ≥ 0.05 hertz deviation (nadir point) from scheduled frequency for the Eastern Interconnection with the applicable unit operating in a frequency responsive mode • ≥ 0.10 hertz deviation (nadir point) from scheduled frequency for the ERCOT and Western Interconnections with the applicable unit operating in a frequency responsive mode • ≥ 0.15 hertz deviation (nadir point) from scheduled frequency for the Quebec Interconnection with the applicable unit operating in a frequency responsive mode 		
<p>NOTE 2: Establishing the recurring ten year unit verification period start date:</p> <ul style="list-style-type: none"> • The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification. 		
<p>NOTE 3: Consideration for early compliance:</p> <p>Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 10 year period from the actual transmittal date if either of the following applies:</p> <ul style="list-style-type: none"> • The Generator Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification • The Generator Owner has an existing verified model that is compliant with the requirements of this standard 		

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Appendix QC-MOD-027-1 Provisions specific to the standard MOD-027-1 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
2. **Number:** MOD-027-1
3. **Purpose:** No specific provision
4. **Applicability:**
 - 4.1. **Functional entities**
No specific provision
 - 4.2. **Facilities**
For the purpose of the requirements contained herein, Facilities that form part of the Main Transmission System (RTP) will be collectively referred as an “applicable unit” that meet the following:
 - 4.2.1 No specific provision
 - 4.2.1.1 No specific provision
 - 4.2.1.2 Individual generating plant consisting of multiple generating units that is part of the Main Transmission System (RTP) with total generation greater than 100 MVA (gross aggregate nameplate rating).
 - 4.2.2 No specific provision
 - 4.2.3 No specific provision
 - 4.2.4 No specific provision
5. **Effective Date:**
 - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx, 201x
 - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx, 201x
 - 5.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

B. Requirements

No specific provision

C. Measures

No specific provision

Standard MOD-027-1 — Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

**Appendix QC-MOD-027-1
Provisions specific to the standard MOD-027-1 applicable in Québec**

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Variances

No specific provision

F. Associated Documents

No specific provision

G. References

No specific provision

MOD-027-1 – Attachment 1

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	xx/xx/201x	New appendix	New

A. Introduction

- 1. Title: Data for Power System Modeling and Analysis**
- 2. Number: MOD-032-1**
- 3. Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. Applicability:

4.1. Functional Entities:

- 4.1.1** Balancing Authority
- 4.1.2** Generator Owner
- 4.1.3** Load Serving Entity
- 4.1.4** Planning Authority and Planning Coordinator (hereafter collectively referred to as “Planning Coordinator”)

This proposed standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

- 4.1.5** Resource Planner
- 4.1.6** Transmission Owner
- 4.1.7** Transmission Planner
- 4.1.8** Transmission Service Provider

5. Effective Date:

MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-1, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority

is not required, MOD-032-1, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. Background:

MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

B. Requirements and Measures

- R1.** Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 1.1.** The data listed in Attachment 1.
 - 1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):
 - 1.2.1.** Data format;
 - 1.2.2.** Level of detail to which equipment shall be modeled;
 - 1.2.3.** Case types or scenarios to be modeled; and
 - 1.2.4.** A schedule for submission of data at least once every 13 calendar months.

- 1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.
- M1.** Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.
- R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M2.** Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.
- R3.** Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
 - 3.1.** Provide either updated data or an explanation with a technical basis for maintaining the current data;
 - 3.2.** Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.
- M3.** Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

- R4.** Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- M4.** Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

“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 may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable 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 Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

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	Lower	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1.	The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1.	The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1; OR The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required components specified

						in Requirement R1.
R2	Long-term Planning	Medium	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided</p>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service</p>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service</p>	<p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s);</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission</p>

			<p>steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified</p>	<p>Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning</p>	<p>Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning</p>	<p>Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;</p> <p>OR</p> <p>The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;</p>
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			by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date.	Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date.	OR The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date.
R3	Long-term Planning	Lower	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service	The Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service

			<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>	<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>	<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>	<p>Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner).</p>
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R4	Long-term Planning	Medium	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee.	The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee.
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D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity¹ responsible for reporting the respective data in the table is identified by brackets “[functional entity]” adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state <i>(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)</i>	dynamics <i>(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)</i>	short circuit
<ol style="list-style-type: none"> 1. Each bus [TO] <ol style="list-style-type: none"> a. nominal voltage b. area, zone and owner 2. Aggregate Demand² [LSE] <ol style="list-style-type: none"> a. real and reactive power* b. in-service status* 3. Generating Units³ [GO, RP (for future planned resources only)] <ol style="list-style-type: none"> a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at 	<ol style="list-style-type: none"> 1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE] 	<ol style="list-style-type: none"> 1. Provide for all applicable elements in column “steady-state” [GO, RP, TO] <ol style="list-style-type: none"> a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

¹ For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

² For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

³ Including synchronous condensers and pumped storage.

<p style="text-align: center;">steady-state</p> <p style="text-align: center;"><i>(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)</i></p>	<p style="text-align: center;">dynamics</p> <p style="text-align: center;"><i>(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)</i></p>	<p style="text-align: center;">short circuit</p>
<ul style="list-style-type: none"> c. real power capabilities in 3a above c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above). d. regulated bus* and voltage set point* (as typically provided by the TOP) e. machine MVA base f. generator step up transformer data (provide same data as that required for transformer under item 6, below) g. generator type (hydro, wind, fossil, solar, nuclear, etc) h. in-service status* 4. AC Transmission Line or Circuit [TO] <ul style="list-style-type: none"> a. impedance parameters (positive sequence) b. susceptance (line charging) c. ratings (normal and emergency)* d. in-service status* 5. DC Transmission systems [TO] 6. Transformer (voltage and phase-shifting) [TO] <ul style="list-style-type: none"> a. nominal voltages of windings b. impedance(s) c. tap ratios (voltage or phase angle)* d. minimum and maximum tap position limits e. number of tap positions (for both the ULTC and NLTC) f. regulated bus (for voltage regulating transformers)* g. ratings (normal and emergency)* h. in-service status* 7. Reactive compensation (shunt capacitors and reactors) [TO] <ul style="list-style-type: none"> a. admittances (MVars) of each capacitor and reactor b. regulated voltage band limits* (if mode of operation not fixed) c. mode of operation (fixed, discrete, continuous, etc.) d. regulated bus* (if mode of operation not fixed) e. in-service status* 8. Static Var Systems [TO] 	<ul style="list-style-type: none"> 6. Wind Turbine Data [GO] 7. Photovoltaic systems [GO] 8. Static Var Systems and FACTS [GO, TO, LSE] 9. DC system models [TO] 10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP] 	<p style="text-align: center;">purposes. [BA, GO, LSE, TO, TSP]</p>

<p style="text-align: center;">steady-state</p> <p style="text-align: center;"><i>(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)</i></p>	<p style="text-align: center;">dynamics</p> <p style="text-align: center;"><i>(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)</i></p>	<p style="text-align: center;">short circuit</p>
<ul style="list-style-type: none"> a. reactive limits b. voltage set point* c. fixed/switched shunt, if applicable d. in-service status* <p>9. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]</p>		

Guidelines and Technical Basis

For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.

The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.

An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.

The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or

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what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

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:

This requirement consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, [here](#):

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

- 1) reduce the quantity of MOD standards;
- 2) add short circuit data as a requirement to the MOD standards; and
- 3) supply data and models:

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- a. add requirement identifying who provides and who receives data;
 - b. identify acceptability;
 - c. standard format;
 - d. how to deal with new technologies (user written models if no standard model exists); and
 - e. shareability.
- 4) These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.
 - 5) The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.
 - 6) Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.

Rationale for R2:

This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that “the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.”

Rationale for R3:

In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.

This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.

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Rationale for R4:

This requirement will replace MOD-014 and MOD-015.

This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.

The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the “ERO or its designee” supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, “industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts.*” (Emphasis added).

This requirement is about the Planning Coordinator’s obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).

For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the “designee” for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection-wide cases.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1
1	May 1, 2014	FERC Order issued approving	See Implementation Plan

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		MOD-032-1.	posted on the Reliability Standards web page for details on enforcement dates for Requirements.
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This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

- 1. Title:** Data for Power System Modeling and Analysis
- 2. Number:** MOD-032-1
- 3. Purpose:** No specific provision
- 4. Applicability:**
 - 4.1. Functional entities**
No specific provision
- 5. Effective Date:**
 - 5.1.** Adoption of the standard by the Régie de l'énergie: Month xx, 201x
 - 5.2.** Adoption of the appendix by the Régie de l'énergie: Month xx, 201x
 - 5.3.** Effective date of the standard and its appendix in Québec: Month xx, 201x
- 6. Background:** No specific provision

B. Requirements and Measures

No specific provision

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

[Compliance Audit](#)

[Self-Certification](#)

[Spot Check](#)

[Compliance Investigation](#)

[Self-Reporting](#)

[Periodic Data Submittal](#)

[Exception Reporting](#)

[Investigation following a complaint](#)~~No specific provision~~

1.4. Additional Compliance Information

No specific provision

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

MOD-032-1 – Attachment 1

No specific provision

Guidelines and Technical Basis

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	Month xx, 201x		New

A. Introduction

1. **Title: Steady-State and Dynamic System Model Validation**
2. **Number: MOD-033-1**
3. **Purpose:** To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

4. **Applicability:**

- 4.1. **Functional Entities:**

- 4.1.1 Planning Authority and Planning Coordinator (hereafter referred to as “Planning Coordinator”)

This proposed standard combines “Planning Authority” with “Planning Coordinator” in the list of applicable functional entities. The NERC Functional Model lists “Planning Coordinator” while the registration criteria list “Planning Authority,” and they are not yet synchronized. Until that occurs, the proposed standard applies to both Planning Authority and Planning Coordinator.

- 4.1.2 Reliability Coordinator

- 4.1.3 Transmission Operator

5. **Effective Date:**

MOD-033-1 shall become effective on the first day of the first calendar quarter that is 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

MOD-033-1 exists in conjunction with MOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.

The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives (to include several remaining directives from FERC Order No. 693), which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (that whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).

The focus of validation in this standard is not Interconnection-wide phenomena, but on the Planning Coordinator's portion of the existing system. The Reliability Standard requires Planning Coordinators to implement a documented data validation process for power flow and dynamics. For the dynamics validation, the target of validation is those events that the Planning Coordinator determines are dynamic local events. A dynamic local event could include such things as closing a transmission line near a generating plant. A dynamic local event is a disturbance on the power system that produces some measurable transient response, such as oscillations. It could involve one small area of the system or a generating plant oscillating against the rest of the grid. The rest of the grid should not have a significant effect. Oscillations involving large areas of the grid are not local events. However, a dynamic local event could also be a subset of a larger disturbance involving large areas of the grid.

B. Requirements and Measures

- R1.** Each Planning Coordinator shall implement a documented data validation process that includes the following attributes: [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]
 - 1.1.** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning power flow model to actual system behavior, represented by a state estimator case or other Real-time data sources, at least once every 24 calendar months through simulation;
 - 1.2.** Comparison of the performance of the Planning Coordinator's portion of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic local event, at least once every 24 calendar months (use a dynamic local event that occurs within 24 calendar months of the last dynamic local event used in comparison, and complete each comparison within 24 calendar months of the dynamic local event). If no dynamic local event occurs within the 24 calendar months, use the next dynamic local event that occurs;
 - 1.3.** Guidelines the Planning Coordinator will use to determine unacceptable differences in performance under Part 1.1 or 1.2; and

1.4. Guidelines to resolve the unacceptable differences in performance identified under Part 1.3.

- M1.** Each Planning Coordinator shall provide evidence that it has a documented validation process according to Requirement R1 as well as evidence that demonstrates the implementation of the required components of the process.
- R2.** Each Reliability Coordinator and Transmission Operator shall provide actual system behavior data (or a written response that it does not have the requested data) to any Planning Coordinator performing validation under Requirement R1 within 30 calendar days of a written request, such as, but not limited to, state estimator case or other Real-time data (including disturbance data recordings) necessary for actual system response validation. [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
- M2.** Each Reliability Coordinator and Transmission Operator shall provide evidence, such as email notices or postal receipts showing recipient and date that it has distributed the requested data or written response that it does not have the data, to any Planning Coordinator performing validation under Requirement R1 within 30 days of a written request in accordance with Requirement R2; or a statement by the Reliability Coordinator or Transmission Operator that it has not received notification regarding data necessary for validation by any Planning Coordinator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

“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 may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable 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 Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to Section 3.0 of Appendix 4C of the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

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	Medium	<p>The Planning Coordinator documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 28 calendar months;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as</p>	<p>The Planning Coordinator documented and implemented a process to validate data but did not address two of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months;</p> <p>OR</p>	<p>The Planning Coordinator documented and implemented a process to validate data but did not address three of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months;</p> <p>OR</p>	<p>The Planning Coordinator did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1;</p> <p>OR</p> <p>The Planning Coordinator did not validate its portion of the system in the power flow model as required by part 1.1 within 36 calendar months;</p> <p>OR</p> <p>The Planning Coordinator did not perform simulation as required by part 1.2 within 36 calendar</p>

			required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation within 28 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 28 calendar months but less than or equal to 32 calendar months.	The Planning Coordinator did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic local event in cases where there is more than 24 months between events) but did perform the simulation in greater than 32 calendar months but less than or equal to 36 calendar months.	months (or the next dynamic local event in cases where there is more than 24 months between events).
R2	Long-term Planning	Lower	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 30 calendar days of the written request, but	The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting Planning Coordinator within 75 calendar days;

			did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 45 calendar days but less than or equal to 60 calendar days.	did provide the data (or written response that it does not have the requested data) in greater than 60 calendar days but less than or equal to 75 calendar days.	OR The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.
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D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Application Guidelines

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to system peak as possible. However, other snapshots of the system could be used if deemed to be more appropriate by the Planning Coordinator. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data if state estimator cases are not available. The comparison of system load distribution and load power factors shall be made on an aggregate company or power flow zone level at a minimum but may also be made on a bus by bus, load pocket (e.g., within a Balancing Authority), or smaller area basis as deemed appropriate by the Planning Coordinator.

The scope of dynamics model validation is intended to be limited, for purposes of part 1.2, to the Planning Coordinator’s planning area, and the intended emphasis under the requirement is on local events or local phenomena, not the whole Interconnection.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Application Guidelines

Determining when a dynamic local event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic local events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic local event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic local events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic local event, the comparison should use the next dynamic local event that occurs). Each comparison must be completed within 24 months of the dynamic local event used. In this manner, the potential problem with a “month 23” dynamic local event described above is resolved. For example, if a PC uses for comparison a dynamic local event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic local event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 500 kV lines should be within 10% or 100 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of MOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the

Application Guidelines

modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

While the validation is focused on the Planning Coordinator's planning area, the model for the validation should be one that contains a wider area of the Interconnection than the Planning Coordinator's area. If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator's area, then the Planning Coordinator should make those changes in coordination with the data provider. However, for some disturbances, the data in the Planning Coordinator's area may not be what is causing the simulations to not match actual responses. These situations should be reported to the Electric Reliability Organization (ERO). The guidelines the Planning Coordinator includes under Part 1.4 could cover these situations.

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:

In FERC Order No. 693, paragraph 1210, the Commission directed inclusion of "a requirement that the models be validated against actual system responses." Furthermore, the Commission directs in paragraph 1211, "that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy." Paragraph 1220 similarly directs validation against actual system responses relative to dynamics system models. In FERC Order 890, paragraph 290, the Commission states that "the models should be updated and benchmarked to actual events." Requirement R1 addresses these directives.

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response, which is consistent with the Commission directives. The validation of the full Interconnection-wide cases is left up to the Electric Reliability Organization (ERO) or its designees, and is not addressed by this standard. The following items were chosen for the validation requirement:

- A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and
- B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Application Guidelines

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of “how” it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees.	Developed as a new standard for system validation to address outstanding directives from FERC Order No. 693 and recommendations from several other sources.
1	May 1, 2014	FERC Order issued approving MOD-033-1.	

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

- 1. Title:** Steady-State and Dynamic System Model Validation
- 2. Number:** MOD-033-1
- 3. Purpose:** No specific provision
- 4. Applicability:**
 - 4.1. Functional entities**
No specific provision
- 5. Effective Date:**
 - 5.1.** Adoption of the standard by the Régie de l'énergie: Month xx, 201x
 - 5.2.** Adoption of the appendix by the Régie de l'énergie: Month xx, 201x
 - 5.3.** Effective date of the standard and its appendix in Québec: Month xx, 201x
- 6. Background:** No specific provision

B. Requirements and Measures

No specific provision

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Periodic Data Submittal

Exception Reporting

Investigation following a complaint~~No specific provision~~

1.4. Additional Compliance Information

No specific provision

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	xx/xx/201x		New

A. Introduction

1. **Title:** Disturbance Monitoring and Reporting Requirements
2. **Number:** PRC-002-2
3. **Purpose:** To have adequate data available to facilitate analysis of Bulk Electric System (BES) Disturbances.
4. **Applicability:**
 - Functional Entities:**
 - 4.1 The Responsible Entity is:
 - 4.1.1 Eastern Interconnection – Planning Coordinator
 - 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator
 - 4.1.3 Western Interconnection – Reliability Coordinator
 - 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator
 - 4.2 Transmission Owner
 - 4.3 Generator Owner
5. **Effective Dates:**

See Implementation Plan

B. Requirements and Measures

- R1.** Each Transmission Owner shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
 - 1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-2, Attachment 1.
 - 1.2. Notify other owners of BES Elements connected to those BES buses, if any, within 90-calendar days of completion of Part 1.1, that those BES Elements require SER data and/or FR data.
 - 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and notify other owners, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan.
- M1.** The Transmission Owner has a dated (electronic or hard copy) list of BES buses for which SER and FR data is required, identified in accordance with PRC-002-2, Attachment 1, and evidence that all BES buses have been re-evaluated within the required intervals under Requirement R1. The Transmission Owner will also have dated (electronic or hard copy) evidence that it notified other owners in accordance with Requirement R1.

- R2.** Each Transmission Owner and Generator Owner shall have SER data for circuit breaker position (open/close) for each circuit breaker it owns connected directly to the BES buses identified in Requirement R1 and associated with the BES Elements at those BES buses. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- M2.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of SER data for circuit breaker position as specified in Requirement R2. Evidence may include, but is not limited to: (1) documents describing the device interconnections and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings; or (3) station drawings.
- R3.** Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns connected to the BES buses identified in Requirement R1: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 3.1** Phase-to-neutral voltage for each phase of each specified BES bus.
- 3.2** Each phase current and the residual or neutral current for the following BES Elements:
- 3.2.1** Transformers that have a low-side operating voltage of 100kV or above.
- 3.2.2** Transmission Lines.
- M3.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of FR data that is sufficient to determine electrical quantities as specified in Requirement R3. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.
- R4.** Each Transmission Owner and Generator Owner shall have FR data as specified in Requirement R3 that meets the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 4.1** A single record or multiple records that include:
- A pre-trigger record length of at least two cycles and a total record length of at least 30-cycles for the same trigger point, or
 - At least two cycles of the pre-trigger data, the first three cycles of the post-trigger data, and the final cycle of the fault as seen by the fault recorder.
- 4.2** A minimum recording rate of 16 samples per cycle.
- 4.3** Trigger settings for at least the following:
- 4.3.1** Neutral (residual) overcurrent.
- 4.3.2** Phase undervoltage or overcurrent.

- M4.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that FR data meets Requirement R4. Evidence may include, but is not limited to: (1) documents describing the device specification (R4, Part 4.2) and device configuration or settings (R4, Parts 4.1 and 4.3), or (2) actual data recordings or derivations.
- R5.** Each Responsible Entity shall: [*Violation Risk Factor: Lower*] [*Time Horizon: Long-term Planning*]
- 5.1** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following:
- 5.1.1** Generating resource(s) with:
- 5.1.1.1** Gross individual nameplate rating greater than or equal to 500 MVA.
- 5.1.1.2** Gross individual nameplate rating greater than or equal to 300 MVA where the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA.
- 5.1.2** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).
- 5.1.3** Each terminal of a high voltage direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current (AC) portion of the converter.
- 5.1.4** One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).
- 5.1.5** Any one BES Element within a major voltage sensitive area as defined by an area with an in-service undervoltage load shedding (UVLS) program.
- 5.2** Identify a minimum DDR coverage, inclusive of those BES Elements identified in Part 5.1, of at least:
- 5.2.1** One BES Element; and
- 5.2.2** One BES Element per 3,000 MW of the Responsible Entity's historical simultaneous peak System Demand.
- 5.3** Notify all owners of identified BES Elements, within 90-calendar days of completion of Part 5.1, that their respective BES Elements require DDR data when requested.
- 5.4** Re-evaluate all BES Elements at least once every five calendar years in accordance with Parts 5.1 and 5.2, and notify owners in accordance with Part 5.3 to implement the re-evaluated list of BES Elements as per the Implementation Plan.
- M5.** The Responsible Entity has a dated (electronic or hard copy) list of BES Elements for which DDR data is required, developed in accordance with Requirement R5, Part 5.1 and Part 5.2; and re-evaluated in accordance with Part 5.4. The Responsible Entity has dated evidence (electronic or hard copy) that each Transmission Owner or Generator

Owner has been notified in accordance with Requirement 5, Part 5.3. Evidence may include, but is not limited to: letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

- R6.** Each Transmission Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 6.1** One phase-to-neutral or positive sequence voltage.
 - 6.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R6, Part 6.1, or the positive sequence current.
 - 6.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.
 - 6.4** Frequency of any one of the voltage(s) in Requirement R6, Part 6.1.
- M6.** The Transmission Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R6. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.
- R7.** Each Generator Owner shall have DDR data to determine the following electrical quantities for each BES Element it owns for which it received notification as identified in Requirement R5: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 7.1** One phase-to-neutral, phase-to-phase, or positive sequence voltage at either the generator step-up transformer (GSU) high-side or low-side voltage level.
 - 7.2** The phase current for the same phase at the same voltage corresponding to the voltage in Requirement R7, Part 7.1, phase current(s) for any phase-to-phase voltages, or positive sequence current.
 - 7.3** Real Power and Reactive Power flows expressed on a three phase basis corresponding to all circuits where current measurements are required.
 - 7.4** Frequency of at least one of the voltages in Requirement R7, Part 7.1.
- M7.** The Generator Owner has evidence (electronic or hard copy) of DDR data to determine electrical quantities as specified in Requirement R7. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings or derivations; or (3) station drawings.
- R8.** Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have continuous data recording and storage. If the equipment was installed prior to the effective date of this standard and

is not capable of continuous recording, triggered records must meet the following:
[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

8.1 Triggered record lengths of at least three minutes.

8.2 At least one of the following three triggers:

- Off nominal frequency trigger set at:

	Low	High
○ Eastern Interconnection	<59.75 Hz	>61.0 Hz
○ Western Interconnection	<59.55 Hz	>61.0 Hz
○ ERCOT Interconnection	<59.35 Hz	>61.0 Hz
○ Hydro-Quebec Interconnection	<58.55 Hz	>61.5 Hz

- Rate of change of frequency trigger set at:

○ Eastern Interconnection	< -0.03125 Hz/sec	> 0.125 Hz/sec
○ Western Interconnection	< -0.05625 Hz/sec	> 0.125 Hz/sec
○ ERCOT Interconnection	< -0.08125 Hz/sec	> 0.125 Hz/sec
○ Hydro-Quebec Interconnection	< -0.18125 Hz/sec	> 0.1875 Hz/sec

- Undervoltage trigger set no lower than 85 percent of normal operating voltage for a duration of 5 seconds.

M8. Each Transmission Owner and Generator Owner has dated evidence (electronic or hard copy) of data recordings and storage in accordance with Requirement R8. Evidence may include, but is not limited to: (1) documents describing the device specifications and configurations, which may include a single design standard as representative for common installations; or (2) actual data recordings.

R9. Each Transmission Owner and Generator Owner responsible for DDR data for the BES Elements identified in Requirement R5 shall have DDR data that meet the following:
[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

9.1 Input sampling rate of at least 960 samples per second.

9.2 Output recording rate of electrical quantities of at least 30 times per second.

M9. The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that DDR data meets Requirement R9. Evidence may include, but is not limited to: (1) documents describing the device specification, device configuration, or settings (R9, Part 9.1; R9, Part 9.2); or (2) actual data recordings (R9, Part 9.2).

- R10.** Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to meet the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 10.1** Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.
- 10.2** Synchronized device clock accuracy within ± 2 milliseconds of UTC.
- M10.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) of time synchronization described in Requirement R10. Evidence may include, but is not limited to: (1) documents describing the device specification, configuration, or setting; (2) time synchronization indication or status; or (3) station drawings.
- R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Regional Entity, or NERC in accordance with the following: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- 11.1** Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.
- 11.2** Data subject to Part 11.1 will be provided within 30-calendar days of a request unless an extension is granted by the requestor.
- 11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.
- 11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.
- 11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.
- M11.** The Transmission Owner or Generator Owner has evidence (electronic or hard copy) that data was submitted upon request in accordance with Requirement R11. Evidence may include, but is not limited to: (1) dated transmittals to the requesting entity with formatted records; (2) documents describing data storage capability, device specification, configuration or settings; or (3) actual data recordings.
- R12.** Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*
- Restore the recording capability, or
 - Submit a Corrective Action Plan (CAP) to the Regional Entity and implement it.

M12. The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Regional Entity and evidence that it implemented the CAP.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) 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 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, Planning Coordinator, and Reliability 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 shall retain evidence of Requirement R1, Measure M1 for five calendar years.

The Transmission Owner shall retain evidence of Requirement R6, Measure M6 for three calendar years.

The Generator Owner shall retain evidence of Requirement R7, Measure M7 for three calendar years.

The Transmission Owner and Generator Owner shall retain evidence of requested data provided as per Requirements R2, R3, R4, R8, R9, R10, R11, and R12, Measures M2, M3, M4, M8, M9, M10, M11, and M12 for three calendar years.

The Responsible Entity (Planning Coordinator or Reliability Coordinator, as applicable) shall retain evidence of Requirement R5, Measure M5 for five calendar years.

If a Transmission Owner, Generator Owner, or Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved or for the time 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

Complaints

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	Lower	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 80 percent but less than 100 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by 30-calendar days or less.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying the other</p>	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 70 percent but less than or equal to 80 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 30-calendar days and less than or equal to 60-calendar days.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part</p>	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for more than 60 percent but less than or equal to 70 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 60-calendar days and less than or equal to 90-calendar days.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part</p>	<p>The Transmission Owner identified the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 for less than or equal to 60 percent of the required BES buses that they own.</p> <p>OR</p> <p>The Transmission Owner evaluated the BES buses as directed by Requirement R1, Part 1.1 or Part 1.3 but was late by greater than 90-calendar days.</p> <p>OR</p> <p>The Transmission Owner as directed by Requirement R1, Part 1.2 was late in notifying one or more other owners by</p>

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			owners by 10-calendar days or less.	1.2 was late in notifying the other owners by greater than 10-calendar days but less than or equal to 20-calendar days.	1.2 was late in notifying the other owners by greater than 20-calendar days but less than or equal to 30-calendar days.	greater than 30-calendar days.
R2	Long-term Planning	Lower	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 80 percent but less than 100 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 70 percent but less than or equal to 80 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 had more than 60 percent but less than or equal to 70 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.	Each Transmission Owner or Generator Owner as directed by Requirement R2 for less than or equal to 60 percent of the total SER data for circuit breaker position (open/close) for each of the circuit breakers at the BES buses identified in Requirement R1.
R3	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 80 percent but less than 100 percent of the total set of required electrical	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 70 percent but less than or equal to 80 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers more than 60 percent but less than or equal to 70 percent of the total set of required	The Transmission Owner or Generator Owner had FR data as directed by Requirement R3, Parts 3.1 and 3.2 that covers less than or equal to 60 percent of the total set of required electrical quantities,

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			quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	electrical quantities, which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.	which is the product of the total number of monitored BES Elements and the number of specified electrical quantities for each BES Element.
R4	Long-term Planning	Lower	The Transmission Owner or Generator Owner had FR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R4.	The Transmission Owner or Generator Owner had FR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R4.
R5	Long-term Planning	Lower	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 80 percent but less than 100 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 70 percent but less than or equal to 80 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for more than 60 percent but less than or equal to 70 percent of the required BES Elements included in Part 5.1.	The Responsible Entity identified the BES Elements for which DDR data is required as directed by Requirement R5 for less than or equal to 60 percent of the required BES Elements included in Part 5.1. OR

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			<p>OR</p> <p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by 30-calendar days or less.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by 10-calendar days or less.</p>	<p>OR</p> <p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 30-calendar days and less than or equal to 60 -calendar days.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 10-calendar days but less than or equal to 20-calendar days.</p>	<p>OR</p> <p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 60-calendar days and less than or equal to 90-calendar days.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying the owners by greater than 20-calendar days but less than or equal to 30-calendar days.</p>	<p>The Responsible Entity identified the BES Elements for DDR as directed by Requirement R5, Part 5.1 or Part 5.4 but was late by greater than 90-calendar days.</p> <p>OR</p> <p>The Responsible Entity as directed by Requirement R5, Part 5.3 was late in notifying one or more owners by greater than 30-calendar days.</p> <p>OR</p> <p>The Responsible Entity failed to ensure a minimum DDR coverage per Part 5.2.</p>
R6	Long-term Planning	Lower	<p>The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 that covered more than 80 percent but less than 100 percent of the</p>	<p>The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 70 percent but less than or equal to 80 percent of the</p>	<p>The Transmission Owner had DDR data as directed by Requirement R6, Parts 6.1 through 6.4 for more than 60 percent but less than or equal to 70 percent of the</p>	<p>The Transmission Owner failed to have DDR data as directed by Requirement R6, Parts 6.1 through 6.4.</p>

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			total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	total required electrical quantities for all applicable BES Elements.	
R7	Long-term Planning	Lower	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 that covers more than 80 percent but less than 100 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 70 percent but less than or equal to 80 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner had DDR data as directed by Requirement R7, Parts 7.1 through 7.4 for more than 60 percent but less than or equal to 70 percent of the total required electrical quantities for all applicable BES Elements.	The Generator Owner failed to have DDR data as directed by Requirement R7, Parts 7.1 through 7.4.
R8	Long-term Planning	Lower	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 80 percent but less than 100 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 70 percent but less than or equal to 80 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner had continuous or non-continuous DDR data, as directed in Requirement R8, for more than 60 percent but less than or equal to 70 percent of the BES Elements they own as determined in Requirement R5.	The Transmission Owner or Generator Owner failed to have continuous or non-continuous DDR data, as directed in Requirement R8, for the BES Elements they own as determined in Requirement R5.

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R9	Long-term Planning	Lower	The Transmission Owner or Generator Owner had DDR data that meets more than 80 percent but less than 100 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 70 percent but less than or equal to 80 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets more than 60 percent but less than or equal to 70 percent of the total recording properties as specified in Requirement R9.	The Transmission Owner or Generator Owner had DDR data that meets less than or equal to 60 percent of the total recording properties as specified in Requirement R9.
R10	Long-term Planning	Lower	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 90 percent but less than 100 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 80 percent but less than or equal to 90 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner had time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for more than 70 percent but less than or equal to 80 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.	The Transmission Owner or Generator Owner failed to have time synchronization per Requirement R10, Parts 10.1 and 10.2 for SER, FR, and DDR data for less than or equal to 70 percent of the BES buses identified in Requirement R1 and BES Elements identified in Requirement R5 as directed by Requirement R10.

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<p>R11</p>	<p>Long-term Planning</p>	<p>Lower</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 30-calendar days but less than 40-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 90 percent but less than 100 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 40-calendar days but less than or equal to 50-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 80 percent but less than or equal to 90 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 provided the requested data more than 50-calendar days but less than or equal to 60-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 provided more than 70 percent but less than or equal to 80 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided more</p>	<p>The Transmission Owner or Generator Owner as directed by Requirement R11, Part 11.1 failed to provide the requested data more than 60-calendar days after the request unless an extension was granted by the requesting authority.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11 failed to provide less than or equal to 70 percent of the requested data.</p> <p>OR</p> <p>The Transmission Owner or Generator Owner as directed by Requirement R11, Parts 11.3 through 11.5 provided less than or equal to 70 percent of the data in</p>
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			than 90 percent of the data but less than 100 percent of the data in the proper data format.	than 80 percent of the data but less than or equal to 90 percent of the data in the proper data format.	than 70 percent of the data but less than or equal to 80 percent of the data in the proper data format.	the proper data format.
R12	Long-term Planning	Lower	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 90-calendar days but less than or equal to 100-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 100-calendar days but less than or equal to 110-calendar days after discovery of the failure.	The Transmission Owner or Generator Owner as directed by Requirement R12 reported a failure and provided a Corrective Action Plan to the Regional Entity more than 110-calendar days but less than or equal to 120-calendar days after discovery of the failure. OR The Transmission Owner or Generator Owner as directed by Requirement R12 submitted a CAP to the Regional Entity but failed to implement it.	The Transmission Owner or Generator Owner as directed by Requirement R12 failed to report a failure and provide a Corrective Action Plan to the Regional Entity more than 120-calendar days after discovery of the failure. OR Transmission Owner or Generator Owner as directed by Requirement R12 failed to restore the recording capability and failed to submit a CAP to the Regional Entity.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

G. References

IEEE C37.111: Common format for transient data exchange (COMTRADE) for power Systems.

IEEE C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME). Standard published 11/09/2011 by IEEE.

NPCC SP6 Report Synchronized Event Data Reporting, revised March 31, 2005

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

U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout in the United States and Canada (Nov. 2003)

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
1	August 2, 2006	Adopted by NERC Board of Trustees	Revised
2	November 13, 2014	Adopted by NERC Board of Trustees	Revised under Project 2007-11 and merged with PRC-018-1.
2	September 24, 2015	FERC approved PRC-005-4. Docket No. RM15-4-000; Order No. 814	

Attachment 1

Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data

(Requirement R1)

To identify monitored BES buses for sequence of events recording (SER) and Fault recording (FR) data required by Requirement 1, each Transmission Owner shall follow sequentially, unless otherwise noted, the steps listed below:

Step 1. Determine a complete list of BES buses that it owns.

For the purposes of this standard, a single BES bus includes physical buses with breakers connected at the same voltage level within the same physical location sharing a common ground grid. These buses may be modeled or represented by a single node in fault studies. For example, ring bus or breaker-and-a-half bus configurations are considered to be a single bus.

Step 2. Reduce the list to those BES buses that have a maximum available calculated three phase short circuit MVA of 1,500 MVA or greater. If there are no buses on the resulting list, proceed to Step 7.

Step 3. Determine the 11 BES buses on the list with the highest maximum available calculated three phase short circuit MVA level. If the list has 11 or fewer buses, proceed to Step 7.

Step 4. Calculate the median MVA level of the 11 BES buses determined in Step 3.

Step 5. Multiply the median MVA level determined in Step 4 by 20 percent.

Step 6. Reduce the BES buses on the list to only those that have a maximum available calculated three phase short circuit MVA higher than the greater of:

- 1,500 MVA or
- 20 percent of median MVA level determined in Step 5.

Step 7. If there are no BES buses on the list: the procedure is complete and no FR and SER data will be required. Proceed to Step 9.

If the list has 1 or more but less than or equal to 11 BES buses: FR and SER data is required at the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 3. Proceed to Step 9.

If the list has more than 11 BES buses: SER and FR data is required on at least the 10 percent of the BES buses determined in Step 6 with the highest maximum available calculated three phase short circuit MVA. Proceed to Step 8.

Step 8. SER and FR data is required at additional BES buses on the list determined in Step 6. The aggregate of the number of BES buses determined in Step 7 and this Step will be at least 20 percent of the BES buses determined in Step 6.

The additional BES buses are selected, at the Transmission Owner's discretion, to provide maximum wide-area coverage for SER and FR data. The following BES bus locations are recommended:

- Electrically distant buses or electrically distant from other DME devices.
- Voltage sensitive areas.
- Cohesive load and generation zones.
- BES buses with a relatively high number of incident Transmission circuits.
- BES buses with reactive power devices.
- Major Facilities interconnecting outside the Transmission Owner's area.

Step 9. The list of monitored BES buses for SER and FR data for Requirement R1 is the aggregate of the BES buses determined in Steps 7 and 8.

Attachment 2
Sequence of Events Recording (SER) Data Format
(Requirement R11, Part 11.3)

Date, Time, Local Time Code, Substation, Device, State¹

08/27/13, 23:58:57.110, -5, Sub 1, Breaker 1, Close

08/27/13, 23:58:57.082, -5, Sub 2, Breaker 2, Close

08/27/13, 23:58:47.217, -5, Sub 1, Breaker 1, Open

08/27/13, 23:58:47.214, -5, Sub 2, Breaker 2, Open

¹ "OPEN" and "CLOSE" are used as examples. Other terminology such as TRIP, TRIP TO LOCKOUT, RECLOSE, etc. is also acceptable.

High Level Requirement Overview

Requirement	Entity	Identify BES Buses	Notification	SER	FR	5 Year Re-evaluation
R1	TO	X	X	X	X	X
R2	TO GO			X		
R3	TO GO				X	
R4	TO GO				X	
Requirement	Entity	Identify BES Elements	Notification	DDR	5 Year Re-evaluation	
R5	RE (PC RC)	X	X	X	X	
R6	TO			X		
R7	GO			X		
R8	TO GO			X		
R9	TO GO			X		
Requirement	Entity	Time Synchronization	Provide SER, FR, DDR Data		SER, FR, DDR Availability	
R10	TO GO	X				
R11	TO GO		X			
R12	TO GO				X	

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 Functional Entities:

When the term “Responsible Entity” is used in PRC-002-2, it specifically refers to those entities listed under 4.1. The Responsible Entity – the Planning Coordinator or Reliability Coordinator, as applicable in each Interconnection – has the best wide-area view of the BES and is most suited to be responsible for determining the BES Elements for which dynamic Disturbance recording (DDR) data is required. The Transmission Owners and Generator Owners will have the responsibility for ensuring that adequate data is available for those BES Elements selected. BES buses where sequence of events recording (SER) and fault recording (FR) data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses. The Transmission Owners and Generator Owners that own BES Elements on those BES buses will have the responsibility for ensuring that adequate data is available.

Rationale for R1:

Analysis and reconstruction of BES events requires SER and FR data from key BES buses. Attachment 1 provides a uniform methodology to identify those BES buses. Repeated testing of the Attachment 1 methodology has demonstrated the proper distribution of SER and FR data collection. Review of actual BES short circuit data received from the industry in response to the DMSDT’s data request (June 5, 2013 through July 5, 2013) illuminated a strong correlation between the available short circuit MVA at a Transmission bus and its relative size and importance to the BES based on (i) its voltage level, (ii) the number of Transmission Lines and other BES Elements connected to the BES bus, and (iii) the number and size of generating units connected to the bus. BES buses with a large short circuit MVA level are BES Elements that have a significant effect on System reliability and performance. Conversely, BES buses with very low short circuit MVA levels seldom cause wide-area or cascading System events, so SER and FR data from those BES Elements are not as significant. After analyzing and reviewing the collected data submittals from across the continent, the threshold MVA values were chosen to provide sufficient data for event analysis using engineering and operational judgment.

Concerns have existed that the defined methodology for bus selection will overly concentrate data to selected BES buses. For the purpose of PRC-002-2, there are a minimum number of BES buses for which SER and FR data is required based on the short circuit level. With these concepts and the objective being sufficient recording coverage for event analysis, the DMSDT developed the procedure in Attachment 1 that utilizes the maximum available calculated three phase short circuit MVA. This methodology ensures comparable and sufficient coverage for SER and FR data regardless of variations in the size and System topology of Transmission Owners across all Interconnections. Additionally, this methodology provides a degree of flexibility for the use of judgment in the selection process to ensure sufficient distribution.

BES buses where SER and FR data is required are best selected by Transmission Owners because they have the required tools, information, and working knowledge of their Systems to determine those buses.

Each Transmission Owner must re-evaluate the list of BES buses at least every five calendar years to address System changes since the previous evaluation. Changes to the BES do not mandate immediate inclusion of BES buses into the currently enforced list, but the list of BES buses will be re-evaluated at least every five calendar years to address System changes since the previous evaluation.

Since there may be multiple owners of equipment that comprise a BES bus, the notification required in R1 is necessary to ensure all owners are notified.

A 90-calendar day notification deadline provides adequate time for the Transmission Owner to make the appropriate determination and notification.

Rationale for R2:

The intent is to capture SER data for the status (open/close) of the circuit breakers that can interrupt the current flow through each BES Element connected to a BES bus. Change of state of circuit breaker position, time stamped according to Requirement R10 to a time synchronized clock, provides the basis for assembling the detailed sequence of events timeline of a power System Disturbance. Other status monitoring nomenclature can be used for devices other than circuit breakers.

Rationale for R3:

The required electrical quantities may either be directly measured or determinable if sufficient FR data is captured (e.g. residual or neutral current if the phase currents are directly measured). In order to cover all possible fault types, all BES bus phase-to-neutral voltages are required to be determinable for each BES bus identified in Requirement R1. BES bus voltage data is adequate for System Disturbance analysis. Phase current and residual current are required to distinguish between phase faults and ground faults. It also facilitates determination of the fault location and cause of relay operation. For transformers (Part 3.2.1), the data may be from either the high-side or the low-side of the transformer. Generator step-up transformers (GSUs) and leads 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 are excluded from Requirement R3 because the fault current contribution from a generator to a fault on the Transmission System will be captured by FR data on the Transmission System, and Transmission System FR will capture faults on the generator interconnection.

Generator Owners may install this capability or, where the Transmission Owners already have suitable FR data, contract with the Transmission Owner. However, when required, the Generator Owner is still responsible for the provision of this data.

Rationale for R4:

Time stamped pre- and post-trigger fault data aid in the analysis of power System operations and determination if operations were as intended. System faults generally persist for a short time period, thus a 30-cycle total minimum record length is adequate. Multiple records allow for legacy microprocessor relays which, when time-synchronized, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle (960 Hz) is required to get sufficient point on wave data for recreating accurate fault conditions.

Rationale for R5:

DDR is used for capturing the BES transient and post-transient response following Disturbances, and the data is used for event analysis and validating System performance. DDR plays a critical role in wide-area Disturbance analysis, and Requirement R5 ensures there is adequate wide-area coverage of DDR data for specific BES Elements to facilitate accurate and efficient event analysis. The Responsible Entity has the best wide-area view of the System and needs to ensure that there are sufficient BES Elements identified for DDR data capture. The identification of BES Elements requiring DDR data as per Requirement R5 is based upon industry experience with wide-area Disturbance analysis and the need for adequate data to facilitate event analysis. Ensuring data is captured for these BES Elements will significantly improve the accuracy of analysis and understanding of why an event occurred, not simply what occurred.

From its experience with changes to the Bulk Electric System that would affect DDR, the DMSDT decided that the five calendar year re-evaluation of the list is a reasonable interval for this review. Changes to the BES do not mandate immediate inclusion of BES Elements into the in force list, but the list of BES Elements will be re-evaluated at least every five calendar years to address System changes since the previous evaluation. However, this standard does not preclude the Responsible Entity from performing this re-evaluation more frequently to capture updated BES Elements.

The Responsible Entity, for the purposes of this standard, is defined as the PC or RC depending upon Interconnection, because they have the best overall perspective for determining wide-area DDR coverage. The Planning Coordinator and Reliability Coordinator assume different functions across the continent; therefore the Responsible Entity is defined in the Applicability Section and used throughout this standard.

The Responsible Entity must notify all owners of the selected BES Elements that DDR data is required for this standard. The Responsible Entity is only required to share the list of selected BES Elements that each Transmission Owner and Generator Owner respectively owns, not the entire list. This communication of selected BES Elements is required to ensure that the owners of the respective BES Elements are aware of their responsibilities under this standard.

Implementation of the monitoring equipment is the responsibility of the respective Transmission Owners and Generator Owners, the timeline for installing this capability is

outlined in the Implementation Plan, and starts from notification of the list from the Responsible Entity. Data for each BES Element as defined by the Responsible Entity must be provided; however, this data can be either directly measured or accurately calculated. With the exception of HVDC circuits, DDR data is only required for one end or terminal of the BES Elements selected. For example, DDR data must be provided for at least one terminal of a Transmission Line or generator step-up (GSU) transformer, but not both terminals. For an interconnection between two Responsible Entities, each Responsible Entity will consider this interconnection independently, and are expected to work cooperatively to determine how to monitor the BES Elements that require DDR data. For an interconnection between two TO's, or a TO and a GO, the Responsible Entity will determine which entity will provide the data. The Responsible Entity will notify the owners that their BES Elements require DDR data.

Refer to the Guidelines and Technical Basis Section for more detail on the rationale and technical reasoning for each identified BES Element in Requirement R5, Part 5.1; monitoring these BES Elements with DDR will facilitate thorough and informative event analysis of wide-area Disturbances on the BES. Part 5.2 is included to ensure wide-area coverage across all Responsible Entities. It is intended that each Responsible Entity will have DDR data for one BES Element and at least one additional BES Element per 3,000 MW of its historical simultaneous peak System Demand.

Rationale for R6:

DDR is used to measure transient response to System Disturbances during a relatively balanced post-fault condition. Therefore, it is sufficient to provide a phase-to-neutral voltage or positive sequence voltage. The electrical quantities can be determined (calculated, derived, etc.).

Because all of the BES buses within a location are at the same frequency, one frequency measurement is adequate.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a BES bus are closed.

Rationale for R7:

A crucial part of wide-area Disturbance analysis is understanding the dynamic response of generating resources. Therefore, it is necessary for Generator Owners to have DDR at either the high- or low-side of the generator step-up transformer (GSU) measuring the specified electrical quantities to adequately capture generator response. This standard defines the 'what' of DDR, not the 'how'. Generator Owners may install this capability or, where the Transmission Owners already have suitable DDR data, contract with the Transmission Owner. However, the Generator Owner is still responsible for the provision of this data.

Rationale for R8:

Large scale System outages generally are an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Data available pre- and post-contingency helps identify the causes and effects of each event leading to outages. Therefore, continuous recording and storage are necessary to ensure sufficient data is available for the entire event.

Existing DDR data recording across the BES may not record continuously. To accommodate its use for the purposes of this standard, triggered records are acceptable if the equipment was installed prior to the effective date of this standard. The frequency triggers are defined based on the dynamic response associated with each Interconnection. The undervoltage trigger is defined to capture possible delayed undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR).

Rationale for R9:

An input sampling rate of at least 960 samples per second, which corresponds to 16 samples per cycle on the input side of the DDR equipment, ensures adequate accuracy for calculation of recorded measurements such as complex voltage and frequency.

An output recording rate of electrical quantities of at least 30 times per second refers to the recording and measurement calculation rate of the device. Recorded measurements of at least 30 times per second provide adequate recording speed to monitor the low frequency oscillations typically of interest during power System Disturbances.

Rationale for R10:

Time synchronization of Disturbance monitoring data is essential for time alignment of large volumes of geographically dispersed records from diverse recording sources. Coordinated Universal Time (UTC) is a recognized time standard that utilizes atomic clocks for generating precision time measurements. All data must be provided in UTC formatted time either with or without the local time offset, expressed as a negative number (the difference between UTC and the local time zone where the measurements are recorded).

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment. The equipment used to measure the electrical quantities must be time synchronized to ± 2 ms accuracy; however, accuracy of the application of this time stamp and therefore the accuracy of the data itself is not mandated. This is because of inherent delays associated with measuring the electrical quantities and events such as breaker closing, measurement transport delays, algorithm and measurement calculation techniques, etc. Ensuring that the monitoring devices internal clocks are within ± 2 ms accuracy will suffice with respect to providing time synchronized data.

Rationale for R11:

Wide-area Disturbance analysis includes data recording from many devices and entities. Standardized formatting and naming conventions of these files significantly improves timely analysis.

Providing the data within 30-calendar days (or the granted extension time), subject to Part 11.1, allows for reasonable time to collect the data and perform any necessary computations or formatting.

Data is required to be retrievable for 10-calendar days inclusive of the day the data was recorded, i.e. a 10-calendar day rolling window of available data. Data hold requests are usually initiated the same or next day following a major event for which data is requested. A 10-

calendar day time frame provides a practical limit on the duration of data required to be stored and informs the requesting entities as to how long the data will be available. The requestor of data has to be aware of the Part 11.1 10-calendar day retrievability because requiring data retention for a longer period of time is expensive and unnecessary.

SER data shall be provided in a simple ASCII .CSV format as outlined in Attachment 2. Either equipment can provide the data or a simple conversion program can be used to convert files into this format. This will significantly improve the data format for event records, enabling the use of software tools for analyzing the SER data.

Part 11.4 specifies FR and DDR data files be provided in conformance with IEEE C37.111, IEEE Standard for Common Format for Transient Exchange (COMTRADE), revision 1999 or later. The use of IEEE C37.111-1999 or later is well established in the industry. C37.111-2013 is a version of COMTRADE that includes an annex describing the application of the COMTRADE standard to synchrophasor data; however, version C37.111-1999 is commonly used in the industry today.

Part 11.5 uses a standardized naming format, C37.232-2011, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), for providing Disturbance monitoring data. This file format allows a streamlined analysis of large Disturbances, and includes critical records such as local time offset associated with the synchronization of the data.

Rationale for R12:

Each Transmission Owner and Generator Owner who owns equipment used for collecting the data required for this standard must repair any failures within 90-calendar days to ensure that adequate data is available for event analysis. If the Disturbance monitoring capability cannot be restored within 90-calendar days (e.g. budget cycle, service crews, vendors, needed outages, etc.), the entity must develop a Corrective Action Plan (CAP) for restoring the data recording capability. The timeline required for the CAP depends on the entity and the type of data required. It is treated as a failure if the recording capability is out of service for maintenance and/or testing for greater than 90-calendar days. An outage of the monitored BES Element does not constitute a failure of the Disturbance monitoring capability.

Guidelines and Technical Basis Section

Introduction

The emphasis of PRC-002-2 is not on how Disturbance monitoring data is captured, but what Bulk Electric System data is captured. There are a variety of ways to capture the data PRC-002-2 addresses, and existing and currently available equipment can meet the requirements of this standard. PRC-002-2 also addresses the importance of addressing the availability of Disturbance monitoring capability to ensure the completeness of BES data capture.

The data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

PRC-002-2 addresses “what” data is recorded, not “how” it is recorded.

Guideline for Requirement R1:

Sequence of events and fault recording for the analysis, reconstruction, and reporting of System Disturbances is important. However, SER and FR data is not required at every BES bus on the BES to conduct adequate or thorough analysis of a Disturbance. As major tools of event analysis, the time synchronized time stamp for a breaker change of state and the recorded waveforms of voltage and current for individual circuits allows the precise reconstruction of events of both localized and wide-area Disturbances.

More quality information is always better than less when performing event analysis. However, 100 percent coverage of all BES Elements is not practical nor required for effective analysis of wide-area Disturbances. Therefore, selectivity of required BES buses to monitor is important for the following reasons:

1. Identify key BES buses with breakers where crucial information is available when required.
2. Avoid excessive overlap of coverage.
3. Avoid gaps in critical coverage.
4. Provide coverage of BES Elements that could propagate a Disturbance.
5. Avoid mandates to cover BES Elements that are more likely to be a casualty of a Disturbance rather than a cause.
6. Establish selection criteria to provide effective coverage in different regions of the continent.

The major characteristics available to determine the selection process are:

1. System voltage level;
2. The number of Transmission Lines into a substation or switchyard;
3. The number and size of connected generating units;
4. The available short circuit levels.

Although it is straightforward to establish criteria for the application of identified BES buses, analysis was required to establish a sound technical basis to fulfill the required objectives.

To answer these questions and establish criteria for BES buses of SER and FR, the DMSDT established a sub-team referred to as the Monitored Value Analysis Team (MVA Team). The MVA Team collected information from a wide variety of Transmission Systems throughout the continent to analyze Transmission buses by the characteristics previously identified for the selection process.

The MVA Team learned that the development of criteria is not possible for adequate SER and FR coverage, based solely upon simple, bright line characteristics, such as the number of lines into a substation or switchyard at a particular voltage level or at a set level of short circuit current. To provide the appropriate coverage, a relatively simple but effective Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data was developed. This Procedure, included as Attachment 1, assists entities in fulfilling Requirement R1 of the standard.

The Methodology for Selecting Buses for Capturing Sequence of Events Recording (SER) and Fault Recording (FR) Data is weighted to buses with higher short circuit levels. This is chosen for the following reasons:

1. The method is voltage level independent.
2. It is likely to select buses near large generation centers.
3. It is likely to select buses where delayed clearing can cause Cascading.
4. Selected buses directly correlate to the Universal Power Transfer equation: Lower Impedance – increased power flows – greater System impact.

To perform the calculations of Attachment 1, the following information below is required and the following steps (provided in summary form) are required for Systems with more than 11 BES buses with three phase short circuit levels above 1,500 MVA.

1. Total number of BES buses in the Transmission System under evaluation.
 - a. Only tangible substation or switchyard buses are included.
 - b. Pseudo buses created for analysis purposes in System models are excluded.
2. Determine the three phase short circuit MVA for each BES bus.
3. Exclude BES buses from the list with short circuit levels below 1,500 MVA.
4. Determine the median short circuit for the top 11 BES buses on the list (position number 6).
5. Multiply median short circuit level by 20 percent.
6. Reduce the list of BES buses to those with short circuit levels higher than 20 percent of the median.
7. Apply SER and FR at BES buses with short circuit levels in the top 10 percent of the list (from 6).

8. Apply SER and FR at BES buses at an additional 10 percent of the list using engineering judgment, and allowing flexibility to factor in the following considerations:
 - Electrically distant BES buses or electrically distant from other DME devices
 - Voltage sensitive areas
 - Cohesive load and generation zones
 - BES buses with a relatively high number of incident Transmission circuits
 - BES buses with reactive power devices
 - Major facilities interconnecting outside the Transmission Owner's area.

For event analysis purposes, more valuable information is attained about generators and their response to System events pre- and post-contingency through DDR data versus SER or FR records. SER data of the opening of the primary generator output interrupting devices (e.g. synchronizing breaker) may not reliably indicate the actual time that a generator tripped; for instance, when it trips on reverse power after loss of its prime mover (e.g. combustion or steam turbine). As a result, this standard only requires DDR data.

The re-evaluation interval of five years was chosen based on the experience of the DMSDT to address changing System configurations while creating balance in the frequency of re-evaluations.

Guideline for Requirement R2:

Analyses of wide-area Disturbances often begin by evaluation of SERs to help determine the initiating event(s) and follow the Disturbance propagation. Recording of breaker operations help determine the interruption of line flows while generator loading is best determined by DDR data, since generator loading can be essentially zero regardless of breaker position. However, generator breakers directly connected to an identified BES bus are required to have SER data captured. It is important in event analysis to know when a BES bus is cleared regardless of a generator's loading.

Generator Owners are included in this requirement because a Generator Owner may, in some instances, own breakers directly connected to the Transmission Owner's BES bus.

Guideline for Requirement R3:

The BES buses for which FR data is required are determined based on the methodology described in Attachment 1 of the standard. The BES Elements connected to those BES buses for which FR data is required include:

- Transformers with a low-side operating voltage of 100kV or above
- Transmission Lines

Only those BES Elements that are identified as BES as defined in the latest in effect NERC definition are to be monitored. For example, radial lines or transformers with low-side voltage less than 100kV are not included.

FR data must be determinable from each terminal of a BES Element connected to applicable BES buses.

Generator step-up transformers (GSU) are excluded from the above based on the following:

- Current contribution from a generator in case of fault on the Transmission System will be captured by FR data on the Transmission System.
- For faults on the interconnection to generating facilities it is sufficient to have fault current data from the Transmission station end of the interconnection. Current contribution from a generator can be readily calculated if needed.

The DMSDT, after consulting with NERC's Event Analysis group, determined that DDR data from selected generator locations was more important for event analysis than FR data.

Recording of Electrical Quantities

For effective fault analysis it is necessary to know values of all phase and neutral currents and all phase-to-neutral voltages. Based on such FR data it is possible to determine all fault types. FR data also augments SERs in evaluating circuit breaker operation.

Current Recordings

The required electrical quantities are normally directly measured. Certain quantities can be derived if sufficient data is measured, for example residual or neutral currents.

Since a Transmission System is generally well balanced, with phase currents having essentially similar magnitudes and phase angle differences of 120°, during normal conditions there is negligible neutral (residual) current. In case of a ground fault the resulting phase current imbalance produces residual current that can be either measured or calculated.

Neutral current, also known as ground or residual current I_r , is calculated as a sum of vectors of three phase currents:

$$I_r = 3 \cdot I_0 = I_A + I_B + I_C$$

I_0 - Zero-sequence current

I_A, I_B, I_C - Phase current (vectors)

Another example of how required electrical quantities can be derived is based on Kirchhoff's Law. Fault currents for one of the BES Elements connected to a particular BES bus can be derived as a vectorial sum of fault currents recorded at the other BES Elements connected to that BES bus.

Voltage Recordings

Voltages are to be recorded or accurately determined at applicable BES buses.

Guideline for Requirement R4:

Pre- and post-trigger fault data along with the SER breaker data, all time stamped to a common clock at millisecond accuracy, aid in the analysis of protection System operations after a fault to determine if a protection System operated as designed. Generally speaking, BES faults persist for a very short time period, approximately 1 to 30 cycles, thus a 30-cycle record length provides adequate data. Multiple records allow for legacy microprocessor relays which, when time synchronized to a common clock, are capable of providing adequate fault data but not capable of providing fault data in a single record with 30-contiguous cycles total.

A minimum recording rate of 16 samples per cycle is required to get accurate waveforms and to get 1 millisecond resolution for any digital input which may be used for FR.

FR triggers can be set so that when the monitored value on the recording device goes above or below the trigger value, data is recorded. Requirement R4, sub-Part 4.3.1 specifies a neutral (residual) overcurrent trigger for ground faults. Requirement R4, sub-Part 4.3.2 specifies a phase undervoltage or overcurrent trigger for phase-to-phase faults.

Guideline for Requirement R5:

DDR data is used for wide-area Disturbance monitoring to determine the System's electromechanical transient and post-transient response and validate System model performance. DDR is typically located based on strategic studies which include angular, frequency, voltage, and oscillation stability. However, for adequately monitoring the System's dynamic response and ensuring sufficient coverage to determine System performance, DDR is required for key BES Elements in addition to a minimum requirement of DDR coverage.

Each Responsible Entity (PC or RC) is required to identify sufficient DDR data capture for, at a minimum, one BES Element and then one additional BES Element per 3,000 MW of historical simultaneous peak System Demand. This DDR data is included to provide adequate System wide coverage across an Interconnection. To clarify, if any of the key BES Elements requiring DDR monitoring are within the Responsible Entity's area, DDR data capability is required. If a Responsible Entity (PC or RC) does not meet the requirements of Part 5.1, additional coverage had to be specified.

Loss of large generating resources poses a frequency and angular stability risk for all Interconnections across North America. Data capturing the dynamic response of these machines during a Disturbance helps the analysis of large Disturbances. Having data regarding generator dynamic response to Disturbances greatly improves understanding of **why** an event occurs rather than what occurred. To determine and provide the basis for unit size criteria, the DMSDT acquired specific generating unit data from NERC's Generating Availability Data System (GADS) program. The data contained generating unit size information for each generating unit in North America which was reported in 2013 to the NERC GADS program. The DMSDT analyzed the spreadsheet data to determine: (i) how many units were above or below selected size

thresholds; and (ii) the aggregate sum of the ratings of the units within the boundaries of those thresholds. Statistical information about this data was then produced, i.e. averages, means and percentages. The DMSDT determined the following basic information about the generating units of interest (current North America fleet, i.e. units reporting in 2013) included in the spreadsheet:

- The number of individual generating units in total included in the spreadsheet.
- The number of individual generating units rated at 20 MW or larger included in the spreadsheet. These units would generally require that their owners be registered as GOs in the NERC CMEP.
- The total number of units within selected size boundaries.
- The aggregate sum of ratings, in MWs, of the units within the boundaries of those thresholds.

The information in the spreadsheet does not provide information by which the plant information location of each unit can be determined, i.e. the DMSDT could not use the information to determine which units were located together at a given generation site or facility.

From this information, the DMSDT was able to reasonably speculate the generating unit size thresholds proposed in Requirement R5, sub-Part 5.1.1 of the standard. Generating resources intended for DDR data recording are those individual units with gross nameplate ratings “greater than or equal to 500 MVA”. The 500 MVA individual unit size threshold was selected because this number roughly accounts for 47 percent of the generating capacity in NERC footprint while only requiring DDR coverage on about 12.5 percent of the generating units. As mentioned, there was no data pertaining to unit location for aggregating plant/facility sizes. However, Requirement R5, sub-Part 5.1.1 is included to capture larger units located at large generating plants which could pose a stability risk to the System if multiple large units were lost due to electrical or non-electrical contingencies. For generating plants, each individual generator at the plant/facility with a gross nameplate rating greater than or equal to 300 MVA must have DDR where the gross nameplate rating of the plant/facility is greater than or equal to 1,000 MVA. The 300 MVA threshold was chosen based on the DMSDT’s judgment and experience. The incremental impact to the number of units requiring monitoring is expected to be relatively low. For combined cycle plants where only one generator has a rating greater than or equal to 300MVA, that is the only generator that would need DDR.

Permanent System Operating Limits (SOLs) are used to operate the System within reliable and secure limits. In particular, SOLs related to angular or voltage stability have a significant impact on BES reliability and performance. Therefore, at least one BES Element of an SOL should be monitored.

The draft standard requires “One or more BES Elements that are part of an Interconnection Reliability Operating Limits (IROLs).” Interconnection Reliability Operating Limits (IROLs) are included because the risk of violating these limits poses a risk to System stability and the potential for cascading outages. IROLs may be defined by a single or multiple monitored BES

Element(s) and contingent BES Element(s). The standard does not dictate selection of the contingent and/or monitored BES Elements. Rather the Drafting Team believes this determination is best made by the Responsible Entity for each IROL considered based on the severity of violating this IROL.

Locations where an undervoltage load shedding (UVLS) program is deployed are prone to voltage instability since they are generally areas of significant Demand. The Responsible Entity (PC or RC) will identify these areas where a UVLS is in service and identify a useful and effective BES Element to monitor for DDR such that action of the UVLS or voltage instability on the BES could be captured. For example, a major 500kV or 230kV substation on the EHV System close to the load pocket where the UVLS is deployed would likely be a valuable electrical location for DDR coverage and would aid in post-Disturbance analysis of the load area's response to large System excursions (voltage, frequency, etc.).

Guideline for Requirement R6:

DDR data shows transient response to System Disturbances after a fault is cleared (post-fault), under a relatively balanced operating condition. Therefore, it is sufficient to provide a single phase-to-neutral voltage or positive sequence voltage. Recording of all three phases of a circuit is not required, although this may be used to compute and record the positive sequence voltage.

The bus where a voltage measurement is required is based on the list of BES Elements defined by the Responsible Entity (PC or RC) in Requirement R5. The intent of the standard is not to require a separate voltage measurement of each BES Element where a common bus voltage measurement is available. For example, a breaker-and-a-half or double-bus configuration with a North (or East) Bus and South (or West) Bus, would require both buses to have voltage recording because either can be taken out of service indefinitely with the targeted BES Element remaining in service. This may be accomplished either by recording both bus voltages separately, or by providing a selector switch to connect either of the bus voltage sources to a single recording input of the DDR device. This component of the requirement is therefore included to mitigate the potential of failed frequency, phase angle, real power, and reactive power calculations due to voltage measurements removed from service while sufficient voltage measurement is actually available during these operating conditions.

It must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

When current recording is required, it should be on the same phase as the voltage recording taken at the location if a single phase-to-neutral voltage is provided. Positive sequence current recording is also acceptable.

For all circuits where current recording is required, Real and Reactive Power will be recorded on a three phase basis. These recordings may be derived either from phase quantities or from positive sequence quantities.

Guideline for Requirement R7:

All Guidelines specified for Requirement R6 apply to Requirement R7. Since either the high- or low-side windings of the generator step-up transformer (GSU) may be connected in delta, phase-to-phase voltage recording is an acceptable voltage recording. As was explained in the Guideline for Requirement R6, the BES is operating under a relatively balanced operating condition and, if needed, phase-to-neutral quantities can be derived from phase-to-phase quantities.

Again it must be emphasized that the data requirements for PRC-002-2 are based on a System configuration assuming all normally closed circuit breakers on a bus are closed.

Guideline for Requirement R8:

Wide-area System outages are generally an evolving sequence of events that occur over an extended period of time, making DDR data essential for event analysis. Pre- and post-contingency data helps identify the causes and effects of each event leading to the outages. This drives a need for continuous recording and storage to ensure sufficient data is available for the entire Disturbance.

Transmission Owners and Generator Owners are required to have continuous DDR for the BES Elements identified in Requirement R6. However, this requirement recognizes that legacy equipment may exist for some BES Elements that do not have continuous data recording capabilities. For equipment that was installed prior to the effective date of the standard, triggered DDR records of three minutes are acceptable using at least one of the trigger types specified in Requirement R8, Part 8.2:

- Off nominal frequency triggers are used to capture high- or low-frequency excursions of significant size based on the Interconnection size and inertia.
- Rate of change of frequency triggers are used to capture major changes in System frequency which could be caused by large changes in generation or load, or possibly changes in System impedance.
- The undervoltage trigger specified in this standard is provided to capture possible sustained undervoltage conditions such as Fault Induced Delayed Voltage Recovery (FIDVR) events. A sustained voltage of 85 percent is outside normal schedule operating voltages and is sufficiently low to capture abnormal voltage conditions on the BES.

Guideline for Requirement R9:

DDR data contains the dynamic response of a power System to a Disturbance and is used for analyzing complex power System events. This recording is typically used to capture short-term

and long-term Disturbances, such as a power swing. Since the data of interest is changing over time, DDR data is normally stored in the form of RMS values or phasor values, as opposed to directly sampled data as found in FR data.

The issue of the sampling rate used in a recording instrument is quite important for at least two reasons: the anti-aliasing filter selection and accuracy of signal representation. The anti-aliasing filter selection is associated with the requirement of a sampling rate at least twice the highest frequency of a sampled signal. At the same time, the accuracy of signal representation is also dependent on the selection of the sampling rate. In general, the higher the sampling rate, the better the representation. In the abnormal conditions of interest (e.g. faults or other Disturbances); the input signal may contain frequencies in the range of 0-400 Hz. Hence, the rate of 960 samples per second (16 samples/cycle) is considered an adequate sampling rate that satisfies the input signal requirements.

In general, dynamic events of interest are: inter-area oscillations, local generator oscillations, wind turbine generator torsional modes, HVDC control modes, exciter control modes, and steam turbine torsional modes. Their frequencies range from 0.1-20 Hz. In order to reconstruct these dynamic events, a minimum recording time of 30 times per second is required.

Guideline for Requirement R10: Time synchronization of Disturbance monitoring data allows for the time alignment of large volumes of geographically dispersed data records from diverse recording sources. A universally recognized time standard is necessary to provide the foundation for this alignment. Coordinated Universal Time (UTC) is the foundation used for the time alignment of records. It is an international time standard utilizing atomic clocks for generating precision time measurements at fractions of a second levels. The local time offset, expressed as a negative number, is the difference between UTC and the local time zone where the measurements are recorded.

Accuracy of time synchronization applies only to the clock used for synchronizing the monitoring equipment.

Time synchronization accuracy is specified in response to Recommendation 12b in the NERC August, 2003, Blackout Final NERC Report Section V Conclusions and Recommendations:

“Recommendation 12b: Facilities owners shall, in accordance with regional criteria, upgrade existing dynamic recorders to include GPS time synchronization...”

Also, from the U.S.-Canada Power System Outage Task Force Interim Report: Causes of the August 14th Blackout, November 2003, in the United States and Canada, page 103:

“Establishing a precise and accurate sequence of outage-related events was a critical building block for the other parts of the investigation. One of the key problems in developing this sequence was that although much of the data pertinent to an event was time-stamped, there was some variance from source to source in how the time-stamping was done, and not all of the time-stamps were synchronized...”

From NPCC's SP6 Report Synchronized Event Data Reporting, revised March 31, 2005, the investigation by the authoring working group revealed that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond, uncertainty being a quantitative descriptor.

Guideline for Requirement R11:

This requirement directs the applicable entities, upon requests from the Responsible Entity, Regional Entity or NERC, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.

Requirement R11, Part 11.1 specifies the maximum time frame of 30-calendar days to provide the data. Thirty calendar days is a reasonable time frame to allow for the collection of data, and submission to the requestor. An entity may request an extension of the 30-day submission requirement. If granted by the requestor, the entity must submit the data within the approved extended time.

Requirement R11, Part 11.2 specifies that the minimum time period of 10-calendar days inclusive of the day the data was recorded for which the data will be retrievable. With the equipment in use that has the capability of recording data, having the data retrievable for the 10-calendar days is realistic and doable. It is important to note that applicable entities should account for any expected delays in retrieving data and this may require devices to have data available for more than 10 days. To clarify the 10-calendar day time frame, an incident occurs on Day 1. If a request for data is made on Day 6, then that data has to be provided to the requestor within 30-calendar days after a request or a granted time extension. However, if a request for the data is made on Day 11, that is outside the 10-calendar days specified in the requirement, and an entity would not be out of compliance if it did not have the data.

Requirement R11, Part 11.3 specifies a Comma Separated Value (CSV) format according to Attachment 2 for the SER data. It is necessary to establish a standard format as it will be incorporated with other submitted data to provide a detailed sequence of events timeline of a power System Disturbance.

Requirement R11, Part 11.4 specifies the IEEE C37.111 COMTRADE format for the FR and DDR data. The IEEE C37.111 is the Standard for Common Format for Transient Data Exchange and is well established in the industry. It is necessary to specify a standard format as multiple submissions of data from many sources will be incorporated to provide a detailed analysis of a power System Disturbance. The latest revision of COMTRADE (C37.111-2013) includes an annex describing the application of the COMTRADE standard to synchophasor data.

Requirement R11, Part 11.5 specifies the IEEE C37.232 COMNAME format for naming the data files of the SER, FR and DDR. The IEEE C37.232 is the Standard for Common Format for Naming Time Sequence Data Files. The first version was approved in 2007. From the August 14, 2003 blackout there were thousands of Fault Recording data files collected. The collected data files

did not have a common naming convention and it was therefore difficult to discern which files came from which utilities and which ones were captured by which devices. The lack of a common naming practice seriously hindered the investigation process. Subsequently, and in its initial report on the blackout, NERC stressed the need for having a common naming practice and listed it as one of its top ten recommendations.

Guideline for Requirement R12:

This requirement directs the respective owners of Transmission and Generator equipment to be alert to the proper functioning of equipment used for SER, FR, and DDR data capabilities for the BES buses and BES Elements, which were established in Requirements R1 and R5. The owners are to restore the capability within 90-calendar days of discovery of a failure. This requirement is structured to recognize that the existence of a “reasonable” amount of capability out-of-service does not result in lack of sufficient data for coverage of the System. Furthermore, 90-calendar days is typically sufficient time for repair or maintenance to be performed. However, in recognition of the fact that there may be occasions for which it is not possible to restore the capability within 90-calendar days, the requirement further provides that, for such cases, the entity submit a Corrective Action Plan (CAP) to the Regional Entity and implement it. These actions are considered to be appropriate to provide for robust and adequate data availability.

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements

United States

Standard	Requirement	Enforcement Date	Inactive Date
PRC-002-2	All	07/01/2016	

Standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements

Appendix QC-PRC-002-2

Provisions specific to the standard PRC-002-2 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. Title: Disturbance Monitoring and Reporting Requirements

2. Number: PRC-002-2

3. Purpose: No specific provision

4. Applicability:

Functional Entities:

No specific provision

Facilities:

- This standard only applies to the facilities of the Main Transmission System (RTP)
- Any reference to the term "BES" shall be replaced by the term "RTP".

5. Effective Date:

5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x

5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x

5.3. Effective date of the standard and its appendix in Québec:

Standard PRC-002-2	Effective date in Québec
<u>R1 and R5</u>	<u>The first day of the first calendar quarter 3 months after the adoption of the standard by the Régie de l'énergie.</u>
<u>R12</u>	<u>The first day of the first calendar quarter 6 months after the adoption of the standard by the Régie de l'énergie.</u>
<u>R2, R3, R4, R6, R7, R8, R9, R10, and R11</u>	<p>To reach 50% compliance¹ <u>The later of the following dates :</u></p> <ul style="list-style-type: none"> • <u>The first day of the first calendar quarter 3 years after the adoption of the standard by the Régie de l'énergie to reach 50% compliance or</u> • <u>July 1st, -2020.</u>
	<p>To reach 100% compliance <u>The later of the following dates :</u></p> <ul style="list-style-type: none"> • <u>The first day of the first calendar quarter 5 years after the adoption of the standard by the Régie de l'énergie or</u> • <u>July 1st, -2022.</u>

Month xx 201x

¹If the entity has designated a single element, the compliance date for the element is the 100% compliance date.

B. Requirements and Measures

Specific provision for R1, M1, R2, R3, R10, R11:

For the purposes of applying this standard, the term “BES bus” (“RTP bus” according to the provisions of section 4 in the present appendix) refers to the buses designated according to appendix 1 as modified in the present appendix. Therefore, requirements and measure subject to this specific provision apply to buses designated by the entity under appendix 1, whether the buses are RTP or not.

~~**R11.** Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for the BES buses identified in Requirement R1 and DDR data for the BES Elements identified in Requirement R5 to the Responsible Entity, Régie de l'énergie in accordance with the following: *[Violation Risk Factor(VRF): Lower] [Time Horizon: Long term Planning]*~~

~~**11.1** Data will be retrievable for the period of 10 calendar days, inclusive of the day the data was recorded.~~

~~**11.2** Data subject to Part 11.1 will be provided within 30 calendar days of a request unless an extension is granted by the requestor.~~

~~**11.3** SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2.~~

~~**11.4** FR and DDR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.~~

~~**11.5** Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.~~

~~**R12.** Each Transmission Owner and Generator Owner shall, within 90 calendar days of the discovery of a failure of the recording capability for the SER, FR or DDR data, either: *[Violation Risk Factor (VRF): Lower] [Time Horizon: Long-term Planning]*~~

- ~~• Restore the recording capability, or~~
- ~~• Submit Corrective Action Plan (CAP) to the Régie de l'énergie~~

~~**M12.** The Transmission Owner or Generator Owner has dated evidence (electronic or hard copy) that meets Requirement R12. Evidence may include, but is not limited to: (1) dated reports of discovery of a failure, (2) documentation noting the date the data recording was restored, (3) SCADA records, or (4) dated CAP transmittals to the Régie de l'énergie and evidence that it implemented the CAP.~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention Compliance

No specific provision

1.3. Compliance Monitoring and Assessment Processes:

No specific provision

1.4. Additional Compliance Information

No specific provision

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

G. References

No specific provision

Attachment 1

~~No specific provision~~

Specific provision for step 1:

When the Transmission Owner determines the complete list of RTP buses it owns, it can, for the purposes of this standard, add one or more non-RTP buses it owns to the list, provided each such bus connects to at least one RTP Element described in Requirements 3.2.1 or 3.2.2.

Attachment 2

No specific provision

High Level Requirement Overview

No specific provision

Rationale

No specific provision

Guidelines and Technical Basis Section

No specific provision

Guideline for Requirement R11:

~~This requirement directs the applicable entities, upon requests from the Responsible Entity or~~

Standard PRC-002-2 — Disturbance Monitoring and Reporting Requirements

Appendix QC-PRC-002-2

Provisions specific to the standard PRC-002-2 applicable in Québec

~~Régie de l'énergie, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.~~

Guideline for Requirement R12:

~~This requirement directs the applicable entities, upon requests from the Responsible Entity or Régie de l'énergie, to provide SER and FR data for BES buses determined in Requirement R1 and DDR data for BES Elements determined as per Requirement R5. To facilitate the analysis of BES Disturbances, it is important that the data is provided to the requestor within a reasonable period of time.~~

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Month xx, 201x	New Appendix	New

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-2
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. **Effective Date:**

This standard is effective on the first day of the first calendar quarter six months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

PRC-006-2 was developed under Project 2008-02: Underfrequency Load Shedding (UFLS). The drafting team revised PRC-006-1 for the purpose of addressing the directive issued in FERC Order No. 763. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, 139 FERC ¶ 61,098 (2012).

B. Requirements and Measures

- 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]*
- 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.
- 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, 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.
- 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.
- 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 = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, of up to 25 percent within the identified island(s). *[VRF: High][Time Horizon: Long-term Planning]*
- 3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - 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-006-2 - 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:
- Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
 - Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
 - Facilities consisting of one or more units connected to the BES at a common bus with total generation above 75 MVA gross nameplate rating.
- 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.
- 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-006-2 - 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-006-2 - 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-006-2 - 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-006-2 — 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-006-2 — 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-006-2 — Attachment 1.

- 4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- 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.
- 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.
- 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.
- 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]*
- 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.

- 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]*
- 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.
- 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]*
- 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.
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. *[VRF: High][Time Horizon: Long-term Planning]*
- 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 implementation , including any Corrective Action Plan, per Requirement R9.
- 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 implementation, including any Corrective Action Plan, as 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]*
- 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 implementation, including any Corrective Action Plan, per Requirement R10.
- 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.

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.

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]*

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.

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.

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.

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

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.

R15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. [*VRF: High*][*Time Horizon: Long-term Planning*]

15.1. For UFLS design assessments performed under Requirement R4 or R5, the Corrective Action Plan shall be developed within the five-year time frame identified in Requirement R4.

15.2. For UFLS design assessments performed under Requirement R12, the Corrective Action Plan shall be developed within the two-year time frame identified in Requirement R12.

M15. Each Planning Coordinator that conducts a UFLS design assessment under Requirement R4, R5, or R12 and determines that the UFLS program does not meet the performance characteristics in Requirement R3, shall have a dated Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, that was developed within the time frame identified in Part 15.1 or 15.2.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence 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, R14, and R15, Measures M1, M2, M3, M4, M5, M12, M14, and M15 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

Complaints

1.4. Additional Compliance Information

None

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</p>	<p>The Planning Coordinator identified an island(s) to serve</p>	<p>The Planning Coordinator identified an island(s) to serve</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>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>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>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>
<p>R3</p>	<p>N/A</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 = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, 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 = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, 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 = $[(\text{load} - \text{actual generation output}) / (\text{load})]$, 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</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				including notification of and a schedule for implementation by UFLS entities within its area
R4	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.	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.	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.	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. 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 R3 for each island identified in Requirement R2

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
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

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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.	<p>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.</p> <p>OR</p> <p>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.</p>	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.	<p>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.</p> <p>OR</p> <p>The UFLS entity failed to provide data to its Planning Coordinator(s) to support maintenance of each Planning Coordinator’s UFLS database.</p>
R9	The UFLS entity provided less than 100% but more than (and including) 95% of automatic tripping of Load in accordance with the UFLS	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	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	The UFLS entity provided less than 85% of automatic tripping of Load in accordance with the UFLS program design and schedule for implementation,

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	program design and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) area in which it owns assets.	including any Corrective Action Plan, as 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 of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 95% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 90% but more than (and including) 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.	The Transmission Owner provided less than 85% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for implementation, including any Corrective Action Plan, as determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
R11	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the	The Planning Coordinator, in whose area a BES islanding event resulting in system frequency excursions below the initializing set points of the UFLS program,

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>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 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>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 specified in Requirement R11, Parts 11.1 or 11.2.</p>	<p>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> <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 all of the Parts</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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 excursions below the initializing set points of the UFLS

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>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</p>
R14	N/A	N/A	N/A	<p>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.</p>
R15	N/A	<p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement</p>	<p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement</p>	<p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period of up to 1 month.</p>	<p>R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 1 month but not more than 2 months.</p>	<p>R3, but failed to develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area.</p> <p>OR</p> <p>The Planning Coordinator determined, through a UFLS design assessment performed under Requirement R4, R5, or R12, that the UFLS program did not meet the performance characteristics in Requirement R3, and developed a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area, but exceeded the permissible time frame for development by a period greater than 2 months.</p>

D. Regional Variances

D.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.

- D.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]
- D.A.3.1.** Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- D.A.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A, either for 30 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- D.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:
- DA.3.3.1.** Individual generating unit greater than 50 MVA (gross nameplate rating) directly connected to the BES
- DA.3.3.2.** Generating plants/facilities greater than 50 MVA (gross aggregate nameplate rating) directly connected to the BES
- DA.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.
- M.D.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 D.A.3 Parts D.A.3.1 through DA3.3.

- D.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 D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; *[VRF: High][Time Horizon: Long-term Planning]*
- D.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-006-2 - Attachment 1A, and
 - D.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-006-2 - Attachment 1A, and
 - D.A.4.3** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
- M.D.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 D.A.4 Parts D.A.4.1 through D.A.4.3.

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D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
DA3	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 D.A.3.1, D.A.3.2, or D.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 D.A.3.1, D.A.3.2, or D.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 D.A.3.1, D.A.3.2, and D.A.3.3 in simulations of underfrequency conditions OR The Planning Coordinator failed to develop a UFLS program.
DA4	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 D.A.3 but simulation failed to include one (1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.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 D3 but simulation failed to include two (2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.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 D3 but simulation failed to include all of the items as specified in Parts D.A.4.1, D.A.4.2 and D.A.4.3. OR

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D#	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 D.A.3

D.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.

D.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]*

M.D.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 D.B.1.

D.B.2. Each Planning Coordinator shall identify one or more islands from the regional review (per D.B.1) to serve as a basis for designing a region-wide coordinated UFLS program including: *[VRF: Medium][Time Horizon: Long-term Planning]*

D.B.2.1. Those islands selected by applying the criteria in Requirement D.B.1, and

D.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.

M.D.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 D.B.1), as a basis for designing a region-wide coordinated UFLS program that meet the criteria in Requirement D.B.2 Parts D.B.2.1 and D.B.2.2.

D.B.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]*

D.B.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and

- D.B.3.2.** Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached, and
- D.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:
 - D.B.3.3.1.** Individual generating units greater than 20 MVA (gross nameplate rating) directly connected to the BES
 - D.B.3.3.2.** Generating plants/facilities greater than 75 MVA (gross aggregate nameplate rating) directly connected to the BES
 - D.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.
- M.D.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 D.B.3 Parts D.B.3.1 through D.B.3.3.
- D.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 D.B.3 for each island identified in Requirement D.B.2. The simulation shall model each of the following: *[VRF: High][Time Horizon: Long-term Planning]*
 - D.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-006-2 - Attachment 1.
 - D.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-006-2 - Attachment 1.
 - D.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-006-2 - Attachment 1.

- D.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-006-2 — Attachment 1.
- D.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-006-2 — Attachment 1.
- D.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-006-2 — Attachment 1.
- D.B.4.7.** Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

M.D.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 D.B.4 Parts D.B.4.1 through D.B.4.7.

D.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]*

D.B.11.1. The performance of the UFLS equipment,

D.B.11.2 The effectiveness of the UFLS program

M.D.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 D.B.11.

- D.B.12.** Each Planning Coordinator, in whose islanding event assessment (per D.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.D.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 D.B.12 and D.B.4 if UFLS program deficiencies are identified in D.B.11.

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.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>

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.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 D.B.2, Parts D.B.2.1 or D.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 D.B.2, Parts D.B.2.1 or D.B.2.2</p> <p>OR</p> <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>
D.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 D.B.3, Parts D.B.3.1, D.B.3.2, or D.B.3.3 in</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 D.B.3, Parts D.B.3.1, D.B.3.2, or D.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 D.B.3, Parts D.B.3.1, D.B.3.2, and D.B.3.3 in</p>

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
		simulations of underfrequency conditions		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.
D.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 D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include one (1) of the items as specified in Requirement	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 D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include two (2) of the items as specified in	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 D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include three (3) of the items as specified in	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 D.B.3 for each island identified in Requirement D.B.2 but the simulation failed to include four (4) or more of the items as

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	Requirement D.B.4, Parts D.B.4.1 through D.B.4.7.	<p>specified in Requirement D.B.4, Parts D.B.4.1 through D.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 D.B.3 for each island identified in Requirement D.B.2</p>
D.B.11	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	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	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	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

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>same islanding event and evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than one year but less than or equal to 13 months of actuation.</p>	<p>evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.11.2 within a time greater than 13 months but less than or equal to 14 months of actuation.</p>	<p>evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.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, 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 D.B.11, Parts D.B.11.1 or D.B.11.2.</p>	<p>evaluated the parts as specified in Requirement D.B.11, Parts D.B.11.1 and D.B.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 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 D.B.11, Parts D.B.11.1 and D.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</p>

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<p>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 D.B.11, Parts D.B.11.1 and D.B.11.2.</p>
D.B.12	N/A	<p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented 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 in greater than two years but less than or equal to 25 months of event actuation.</p>	<p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented 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 in greater than 25 months but less than or equal to 26 months of event actuation.</p>	<p>The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement D.B.11, participated in and documented 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 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 D.B.11, failed to participate in</p>

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D #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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

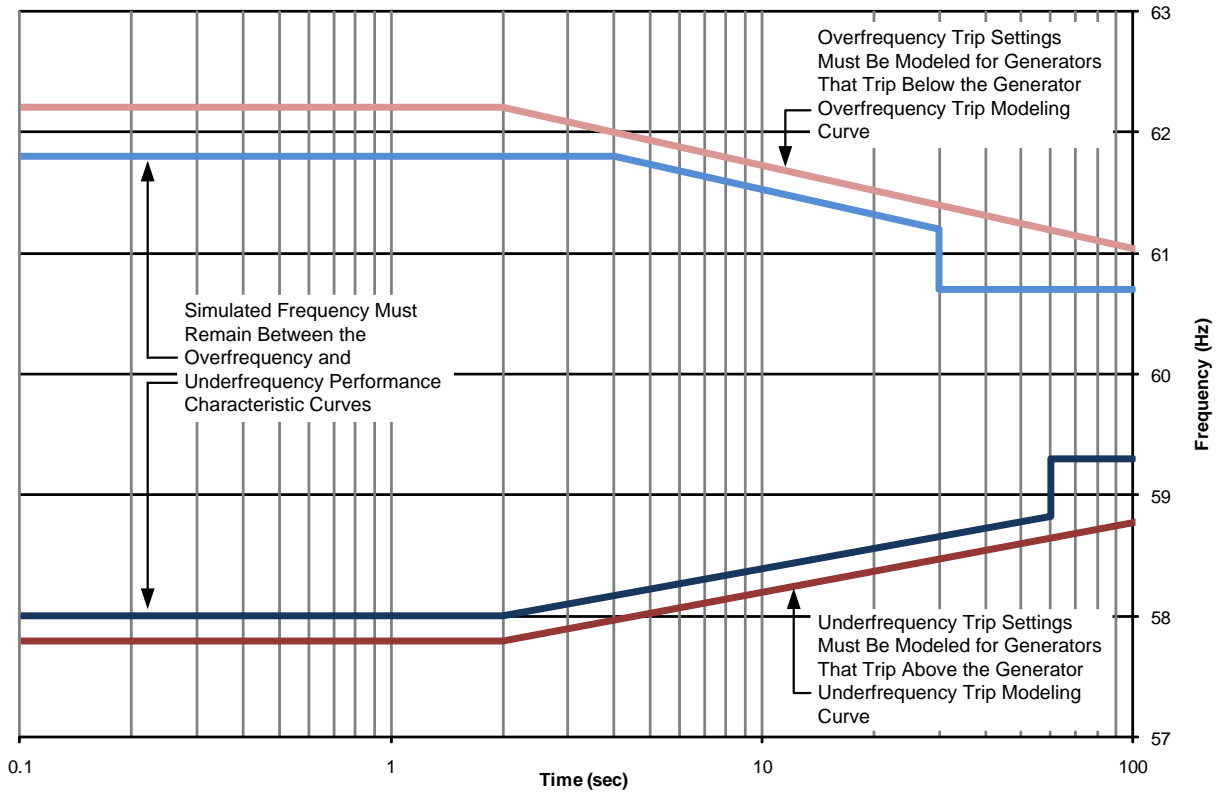
E. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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.	
2	November 13, 2014	Adopted by the Board of Trustees	Revisions made under Project 2008-02: Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS) to address directive issued in FERC Order No. 763. Revisions to existing Requirement R9 and R10 and addition of new Requirement R15.

PRC-006-2 – 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)

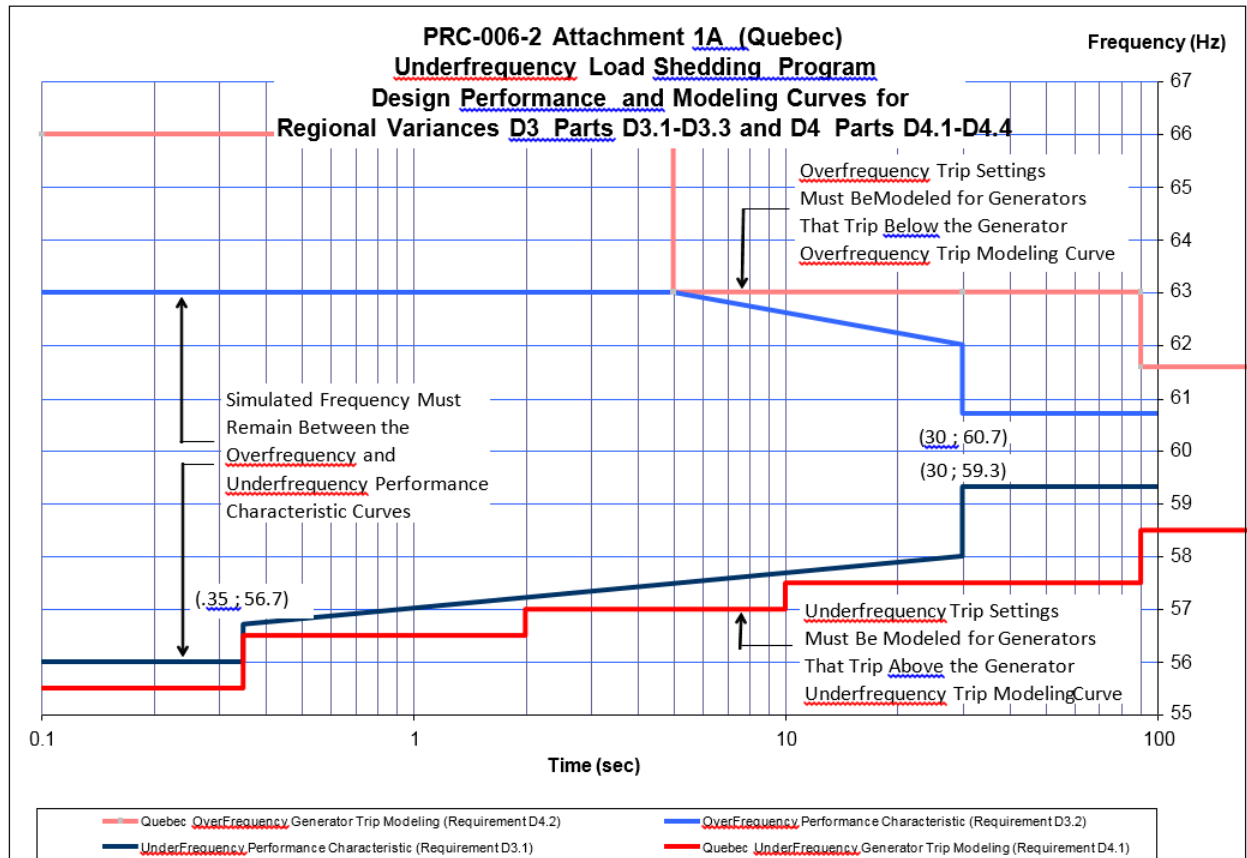
Curve Definitions

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
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Standard PRC-006-2 — Automatic Underfrequency Load Shedding

$t \leq 2 \text{ s}$	$t > 2 \text{ s}$	$t \leq 2 \text{ s}$	$2 \text{ s} < t \leq 60 \text{ s}$	$t > 60 \text{ s}$
$f = 57.8$ Hz	$f = 0.575\log(t) + 57.63$ Hz	$f = 58.0$ Hz	$f = 0.575\log(t) + 57.83$ Hz	$f = 59.3$ Hz



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 R9:

The “Corrective Action Plan” language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word “application” was replaced with “implementation.” (See Requirements R3, R14 and R15)

Rationale for R10:

The “Corrective Action Plan” language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.

Also, to achieve consistency of terminology throughout this standard, the word “application” was replaced with “implementation.” (See Requirements R3, R14 and R15)

Rationale for R15:

Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.

A “Corrective Action Plan” is defined in the NERC Glossary of Terms as, “a list of actions and an associated timetable for implementation to remedy a specific problem.” Thus, the Corrective Action Plan developed by the PC will identify the specific timeframe for an entity to implement corrections to remedy any deficiencies identified by the PC as a result of an assessment.

Standard PRC-006-2 — Automatic Underfrequency Load Shedding

Appendix QC-PRC-006-2

Provisions specific to the standard PRC-006-2 applicable in Québec

This appendix establishes specific provisions for the application of the standard in Québec. Provisions of the standard and of its appendix must be read together for the purposes of understanding and interpretation. Where the standard and appendix differ, the appendix shall prevail.

A. Introduction

1. **Title:** Automatic Underfrequency Load Shedding
2. **Number:** PRC-006-2
3. **Purpose:** No specific provision
4. **Applicability:**
No specific provision
5. **Effective Date:**
 - 5.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x
 - 5.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x
 - 5.3. Effective date of the standard and its appendix in Québec: 1st day of the first quarter 30 days following the adoption of the standard by the Régie de l'énergie. [Month xx 201x]
6. **Background:**
No specific provision

B. Requirements and Measures

No specific provision

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Régie de l'énergie is responsible, in Québec, for compliance monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Evidence Retention

No specific provision

1.3. Compliance Monitoring and Assessment Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

See section D.A.

D. Regional Variances

D.A. Regional Variance for the Quebec Interconnexion

D.A.3. 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 each of these extreme events:

- Loss of the entire capability of a generating station.
- Loss of all transmission circuits emanating from a generating station, switching station, substation or dc terminal.
- Loss of all transmission circuits on a common right-of-way.
- Three-phase fault with failure of a circuit breaker to operate and correct operation of a breaker failure protection system and its associated breakers.
- Three-phase fault on a circuit breaker, with normal fault clearing.
- The operation or partial operation of a SPS for an event or condition for which it was not intended to operate.

D.A.3.1. Frequency shall remain above the Underfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A (Québec Appendix), either for 60 seconds or until a steady-state condition between 59.0 Hz and 60.7 Hz is reached, and

D.A.3.2. Frequency shall remain below the Overfrequency Performance Characteristic curve in PRC-006-2 - Attachment 1A (Québec Appendix), either for 60 seconds or until a steady-state condition between 59.0 Hz and 60.7 Hz is reached, and

D.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 RTP generator bus and associated generator step-up transformer high-side bus.

D.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 D.A.3 for each island identified in Requirement R2. The simulation shall model each of the following; [*VRF: High*][*Time Horizon: Long-term Planning*]

D.A.4.1 Underfrequency trip settings of individual generating units that are part of RTP facilities that trip above the Generator Underfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A (Québec Appendix), and

D.A.4.2 Overfrequency trip settings of individual generating units that are part of the RTP plants/facilities that trip below the Generator Overfrequency Trip Modeling curve in PRC-006-2 - Attachment 1A (Québec Appendix), and

D.A.4.3 Any automatic Load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.

Standard PRC-006-2 — Automatic Underfrequency Load Shedding

Appendix QC-PRC-006-2

Provisions specific to the standard PRC-006-2 applicable in Québec

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.3	N/A	<p>The Planning Coordinator developed a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, but failed to meet one (1) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.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, but failed to meet two (2) of the performance characteristic in Parts D.A.3.1, D.A.3.2, or D.A.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, but failed to meet all the performance characteristic in Parts D.A.3.1, D.A.3.2, and D.A.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>
D.A.4	N/A	<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 D.A.3 but the simulation failed to include one</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 D.A.3 but the simulation failed to include two</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 D.A.3 but the simulation failed to include all of</p>

Standard PRC-006-2 — Automatic Underfrequency Load Shedding

Appendix QC-PRC-006-2

Provisions specific to the standard PRC-006-2 applicable in Québec

D#	Lower VSL	Moderate VSL	High VSL	Severe VSL
		(1) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	(2) of the items as specified in Parts D.A.4.1, D.A.4.2 or D.A.4.3.	the items as specified in Parts D.A.4.1, D.A.4.2 and D.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 D.A.3

D.B. Regional Variance for the Western Electricity Coordinating Council

No specific provision

E. Associated Documents

No specific provision

Appendix 1

No specific provision

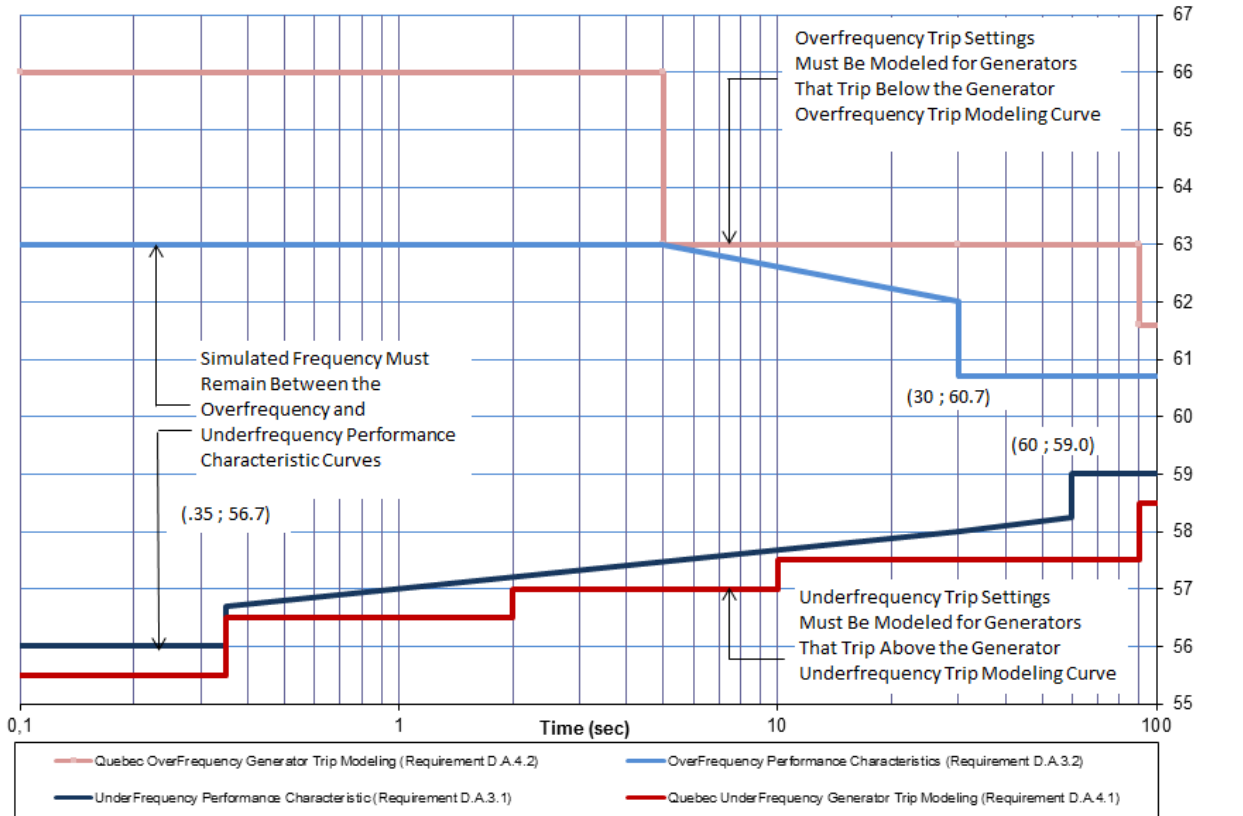
Appendix 1A

Standard PRC-006-2 — Automatic Underfrequency Load Shedding

Appendix QC-PRC-006-2

Provisions specific to the standard PRC-006-2 applicable in Québec

PRC-006-3 Attachment 1A (Quebec)
 Underfrequency Load Shedding Program
 Design Performance and Modeling Curves for
 Regional Variances D.A.3 Parts D.A.3.1-DA.3.3 and D.A.4 Parts D.A.4.1-D.A.4.3



Rationale

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Mont xx, 201x	New appendix	New