

**Normes de fiabilité de la NERC
(version anglaise)**

A. Introduction

Title: Frequency Response and Frequency Bias Setting

Number: BAL-003-1

Purpose: To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

Applicability:

1.1. Balancing Authority

1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

1.2. Frequency Response Sharing Group

Effective Date:

1.3. In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.

1.4. In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.

B. Requirements

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [*Risk Factor: Medium*][*Time Horizon: Real-time Operations*]

- R2.** Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*
- R3.** Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*
- 1.1** Less than zero at all times, and
 - 1.2** Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.
- R4.** Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*
- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
 - The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

C. Measures

- M1.** Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.
- M2.** The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.
- M3.** The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of

the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

- M4.** The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity is the Compliance Enforcement Authority except where the responsible entity works for the Regional Entity. Where the responsible entity works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.

1.2. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.3. 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 Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.4. Additional Compliance Information

For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection was equal to or more negative than the Interconnection's IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The summation of the Balancing Authorities' FRM within an Interconnection did not meet its IFRO, and the Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or by more than 15 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation

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	Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing

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	Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.
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E. Regional Variance

None

F. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

G. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition

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0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	

Attachment A

BAL-003-1 Frequency Response & Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- CB_R which is the statistically determined ratio of the Point C to Value B
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Starting Frequency (F_{Start})	59.974	59.976	59.963	59.972	Hz
Prevailing UFLS First Step	59.5*	59.5	59.3	58.5	Hz
Base Delta Frequency (DF_{Base})	0.474	0.476	0.663	1.472	Hz
CC_{ADJ}	0.007	0.004	0.012	N/A	Hz
Delta Frequency (DF_{CC})	0.467	0.472	0.651	1.472	Hz
CB_R	1.000	1.625	1.377	1.550	
Delta Frequency (DF_{CBR})	0.467	0.291	0.473	0.949	Hz
BC'_{ADJ}	0.018	N/A	N/A	N/A	Hz
Max. Delta Frequency (MDF)	0.449	0.291	0.473	0.949	
Resource Contingency Criteria (RCC)	4,500	2,740	2,750	1,700	MW
Credit for Load Resources (CLR)		300	1,400**		MW
IFRO	-1,002	-840	-286	-179	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$FRO_{BA} = IFRO \times \frac{\text{Annual Gen}_{BA} + \text{Annual Load}_{BA}}{\text{Annual Gen}_{Int} + \text{Annual Load}_{Int}}$$

Where:

- Annual Gen_{BA} is the total annual “Output of Generating Plants” within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load_{BA} is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO’s.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs’ Form 1s, with a summary spreadsheet that contains the sum of each participant’s individual event performance.

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Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

There are occasions when changes are needed to Bias Settings outside of the normal schedule.

Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.

If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.

If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.

Frequency Response Measure (FRM)

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its

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Frequency Response, expressed in MW/0.1Hz” as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_i) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event NA_i and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_i (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority’s Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA’s data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority’s FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a “Point C” that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

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Target Date	Activity
April 30	The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).
May 10	Form1 is posted with selected events from the first quarter for BA usage by the ERO.
May 15	The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.
July 15	The BAs provide load and generation data as described in Attachment A to the ERO.
July 30	The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).
August 10	Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.
October 30	The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)
November 10	Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.
November 20	If necessary, the ERO provides any updates to the necessary Frequency Response.
November 20	The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.
January 30	The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).
2 nd business day in February	Form1 is posted with all selected events for the year for BA usage by the ERO.
February 10	The ERO assigns FRO values to the BAs for the upcoming year.
March 7	BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.
March 24	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.
Any time during first 3 business days of April (unless specified otherwise by the ERO)	The BA implements any changes to their FBS and L10 value.

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Appendix QC-BAL-003-1

Provisions specific to the standard BAL-003-1 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

Title: Frequency Response and Frequency Bias Setting

Number: BAL-003-1

Purpose: No specific provision

Applicability: No specific provision

Effective Date:

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

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

1.5. 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

E. Regional Variance

No specific provision

F. Associated Documents

No specific provision

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Appendix QC-BAL-003-1

Provisions specific to the standard BAL-003-1 applicable in Québec

Attachment A

No specific provision

Revision History

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

A. Introduction

- 1. Title:** Automatic Generation Control
- 2. Number:** BAL-005-0.2b
- 3. Purpose:** This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.
- 4. Applicability:**
 - 4.1.** Balancing Authorities
 - 4.2.** Generator Operators
 - 4.3.** Transmission Operators
 - 4.4.** Load Serving Entities
- 5. Effective Date:** May 13, 2009

B. Requirements

- R1.** All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.
 - R1.1.** Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.
 - R1.2.** Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.
 - R1.3.** Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.
- R2.** Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard. (Retirement approved by FERC effective January 21, 2014.)
- R3.** A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.
- R4.** A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.
- R5.** A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.
- R6.** The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

- R7.** The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.
- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.
- R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical

locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

- R16.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.
- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25 % of full scale
Remote terminal unit	≤ 0.25 % of full scale
Potential transformer	≤ 0.30 % of full scale
Current transformer	≤ 0.50 % of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

- 1.1.1.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.
- 1.1.2.** Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

- 1.3.1.** Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.
- 1.3.2.** Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or

Standard BAL-005-0.2b — Automatic Generation Control

Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

F. Associated Documents

- Appendix 1 — Interpretation of Requirement R17 (February 12, 2008).

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by NERC Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0a	December 19, 2007	Added Appendix 1 – Interpretation of R17 approved by BOT on May 2, 2007	Addition
0a	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial	Errata
0b	February 12, 2008	Replaced Appendix 1 – Interpretation of R17 approved by BOT on February 12, 2008 (BOT approved retirement of Interpretation included in BAL-005-0a)	Replacement
0.1b	October 29, 2008	BOT approved errata changes; updated version number to “0.1b”	Errata
0.1b	May 13, 2009	FERC approved – Updated Effective Date	Addition
0.2b	March 8, 2012	Errata adopted by Standards Committee; (replaced Appendix 1 with the FERC-approved revised interpretation of R17 and corrected standard version referenced in Interpretation by changing from “BAL-005-1” to “BAL-005-0)	Errata
0.2b	September 13, 2012	FERC approved – Updated Effective Date	Addition
0.2b	February 7, 2013	R2 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.	
0.2b	November 21, 2013	R2 and associated elements approved by FERC	

		for retirement as part of the Paragraph 81 project (Project 2013-02) effective January 21, 2014.	
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Appendix 1

Effective Date: August 27, 2008 (U.S.)

Interpretation of BAL-005-0 Automatic Generation Control, R17

Request for Clarification received from PGE on July 31, 2007

PGE requests clarification regarding the measuring devices for which the requirement applies, specifically clarification if the requirement applies to the following measuring devices:

- *Only equipment within the operations control room*
- *Only equipment that provides values used to calculate AGC ACE*
- *Only equipment that provides values to its SCADA system*
- *Only equipment owned or operated by the BA*
- *Only to new or replacement equipment*
- *To all equipment that a BA owns or operates*

BAL-005-0

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤ 0.25% of full scale
Remote terminal unit	≤ 0.25% of full scale
Potential transformer	≤ 0.30% of full scale
Current transformer	≤ 0.50% of full scale

Existing Interpretation Approved by Board of Trustees May 2, 2007

BAL-005-0, Requirement 17 requires that the Balancing Authority check and calibrate its control room time error and frequency devices against a common reference at least annually. The requirement to “annually check and calibrate” does not address any devices outside of the operations control room.

The table represents the design accuracy of the listed devices. There is no requirement within the standard to “annually check and calibrate” the devices listed in the table, unless they are included in the control center time error and frequency devices.

Interpretation provided by NERC Frequency Task Force on September 7, 2007 and Revised on November 16, 2007

As noted in the existing interpretation, BAL-005-0 Requirement 17 applies only to the time error and frequency devices that provide, or in the case of back-up equipment may provide, input into the reporting or compliance ACE equation or provide real-time time error or frequency information to the system operator. Frequency inputs from other sources that are for reference only are excluded. The time error and

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frequency measurement devices may not necessarily be located in the system operations control room or owned by the Balancing Authority; however the Balancing Authority has the responsibility for the accuracy of the frequency and time error measurement devices. No other devices are included in R 17. The other devices listed in the table at the end of R17 are for reference only and do not have any mandatory calibration or accuracy requirements.

New or replacement equipment that provides the same functions noted above requires the same calibrations. Some devices used for time error and frequency measurement cannot be calibrated as such. In this case, these devices should be cross-checked against other properly calibrated equipment and replaced if the devices do not meet the required level of accuracy.

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Appendix QC-BAL-005-0.2b

Provisions specific to the standard BAL-005-0.2b 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 Generation Control
2. **Number:** BAL-005-0.2b
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: Month xx, 201x

B. Requirements

No specific provision

C. Measures

No specific provision

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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. Compliance Monitoring Period and Reset Timeframe

No specific provision

1.3. Data Retention

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Levels of Non-Compliance

No specific provision

E. Regional Differences

No specific provision

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Appendix QC-BAL-005-0.2b

Provisions specific to the standard BAL-005-0.2b applicable in Québec

F. Associated Documents

No specific provision

Appendix 1

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	October 30, 2013	New appendix	New
1	Month xx, 201x	<ul style="list-style-type: none">• Modification of adoption dates	

A. Introduction

1. **Title:** Event Reporting
2. **Number:** EOP-004-2
3. **Purpose:** To improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities.
4. **Applicability:**
 - 4.1. **Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following functional entities will be collectively referred to as “Responsible Entity.”
 - 4.1.1. Reliability Coordinator
 - 4.1.2. Balancing Authority
 - 4.1.3. Transmission Owner
 - 4.1.4. Transmission Operator
 - 4.1.5. Generator Owner
 - 4.1.6. Generator Operator
 - 4.1.7. Distribution Provider

5. Effective Dates:

The first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities. In those jurisdictions where regulatory approval is not required, the standard shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

NERC established a SAR Team in 2009 to investigate and propose revisions to the CIP-001 and EOP-004 Reliability Standards. The team was asked to consider the following:

1. CIP-001 could be merged with EOP-004 to eliminate redundancies.
2. Acts of sabotage have to be reported to the DOE as part of EOP-004.
3. Specific references to the DOE form need to be eliminated.
4. EOP-004 had some ‘fill-in-the-blank’ components to eliminate.

The development included other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient Bulk Electric System reliability standards.

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009.

The DSR SDT developed a concept paper to solicit stakeholder input regarding the proposed reporting concepts that the DSR SDT had developed. The posting of the concept paper sought comments from stakeholders on the “road map” that will be used by the DSR SDT in updating or revising CIP-001 and EOP-004. The concept paper provided stakeholders the background information and thought process of the DSR SDT. The DSR SDT has reviewed the existing standards, the SAR, issues from the NERC issues database and FERC Order 693 Directives in order to determine a prudent course of action with respect to revision of these standards.

B. Requirements and Measures

- R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-004-2 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity’s Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes, but is not limited to the protocol(s) and each organization identified to receive an event report for event types specified in EOP-004-2 Attachment 1 and in accordance with the entity responsible for reporting.

- R2.** Each Responsible Entity shall report events per their Operating Plan within 24 hours of recognition of meeting an event type threshold for reporting or by the end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). *[Violation Risk Factor: Medium] [Time Horizon: Operations Assessment]*

- M2.** Each Responsible Entity will have as evidence of reporting an event, copy of the completed EOP-004-2 Attachment 2 form or a DOE-OE-417 form; and evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating the event report was submitted within 24 hours of recognition of meeting the threshold for reporting or by the

end of the next business day if the event occurs on a weekend (which is recognized to be 4 PM local time on Friday to 8 AM Monday local time). (R2)

- R3.** Each Responsible Entity shall validate all contact information contained in the Operating Plan pursuant to Requirement R1 each calendar year. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]
- M3.** Each Responsible Entity will have dated records to show that it validated all contact information contained in the Operating Plan each calendar year. Such evidence may include, but are not limited to, dated voice recordings and operating logs or other communication documentation. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

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

1.2 Evidence Retention

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

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

- Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirements R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirements R2, R3 and Measure M2, M3.

If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4 Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Responsible Entity had an Operating Plan, but failed to include one applicable event type.	The Responsible Entity had an Operating Plan, but failed to include two applicable event types.	The Responsible Entity had an Operating Plan, but failed to include three applicable event types.	The Responsible Entity had an Operating Plan, but failed to include four or more applicable event types. OR The Responsible Entity failed to have an event reporting Operating Plan.

EOP-004-2 — Event Reporting

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Operations Assessment	Medium	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 36 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 36 hours but less than or equal to 48 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours.</p>	<p>The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 60 hours after meeting an event threshold for reporting.</p> <p>OR</p> <p>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours.</p> <p>OR</p> <p>The Responsible Entity failed to submit a report for an event in EOP-004 Attachment 1.</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	Medium	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by less than one calendar month.</p> <p>OR</p> <p>The Responsible Entity validated 75% but less than 100% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by one calendar month or more but less than two calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 50% and less than 75% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by two calendar months or more but less than three calendar months.</p> <p>OR</p> <p>The Responsible Entity validated 25% and less than 50% of the contact information contained in the Operating Plan.</p>	<p>The Responsible Entity validated all contact information contained in the Operating Plan but was late by three calendar months or more.</p> <p>OR</p> <p>The Responsible Entity validated less than 25% of contact information contained in the Operating Plan.</p>

D. Variances

None.

E. Interpretations

None.

F. References

Guideline and Technical Basis (attached)

EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written Event Report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780.

Submit EOP-004 Attachment 2 (or DOE-OE-417) pursuant to Requirements R1 and R2.

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Damage or destruction of a Facility	RC, BA, TOP	Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in actions to avoid a BES Emergency.
Damage or destruction of a Facility	BA, TO, TOP, GO, GOP, DP	Damage or destruction of its Facility that results from actual or suspected intentional human action.
Physical threats to a Facility	BA, TO, TOP, GO, GOP, DP	Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility. OR Suspicious device or activity at a Facility. Do not report theft unless it degrades normal operation of a Facility.

EOP-004-2 — Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Physical threats to a BES control center	RC, BA, TOP	Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center. OR Suspicious device or activity at a BES control center.
BES Emergency requiring public appeal for load reduction	Initiating entity is responsible for reporting	Public appeal for load reduction event.
BES Emergency requiring system-wide voltage reduction	Initiating entity is responsible for reporting	System wide voltage reduction of 3% or more.
BES Emergency requiring manual firm load shedding	Initiating entity is responsible for reporting	Manual firm load shedding \geq 100 MW.
BES Emergency resulting in automatic firm load shedding	DP, TOP	Automatic firm load shedding \geq 100 MW (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS).
Voltage deviation on a Facility	TOP	Observed within its area a voltage deviation of \pm 10% of nominal voltage sustained for \geq 15 continuous minutes.

EOP-004-2 — Event Reporting

Event Type	Entity with Reporting Responsibility	Threshold for Reporting
IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only)	RC	Operate outside the IROL for time greater than IROL T_v (all Interconnections) or Operate outside the SOL for more than 30 minutes for Major WECC Transfer Paths (WECC only).
Loss of firm load	BA, TOP, DP	Loss of firm load for ≥ 15 Minutes: ≥ 300 MW for entities with previous year's demand $\geq 3,000$ OR ≥ 200 MW for all other entities
System separation (islanding)	RC, BA, TOP	Each separation resulting in an island ≥ 100 MW
Generation loss	BA, GOP	Total generation loss, within one minute, of : $\geq 2,000$ MW for entities in the Eastern or Western Interconnection OR $\geq 1,000$ MW for entities in the ERCOT or Quebec Interconnection
Complete loss of off-site power to a nuclear generating plant (grid supply)	TO, TOP	Complete loss of off-site power affecting a nuclear generating station per the Nuclear Plant Interface Requirement

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Event Type	Entity with Reporting Responsibility	Threshold for Reporting
Transmission loss	TOP	Unexpected loss within its area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing).
Unplanned BES control center evacuation	RC, BA, TOP	Unplanned evacuation from BES control center facility for 30 continuous minutes or more.
Complete loss of voice communication capability	RC, BA, TOP	Complete loss of voice communication capability affecting a BES control center for 30 continuous minutes or more.
Complete loss of monitoring capability	RC, BA, TOP	Complete loss of monitoring capability affecting a BES control center for 30 continuous minutes or more such that analysis capability (i.e., State Estimator or Contingency Analysis) is rendered inoperable.

EOP-004 - Attachment 2: Event Reporting Form

EOP-004 Attachment 2: Event Reporting Form			
<p>Use this form to report events. The Electric Reliability Organization will accept the DOE OE-417 form in lieu of this form if the entity is required to submit an OE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net , Facsimile 404-446-9770 or voice: 404-446-9780.</p>			
Task	Comments		
1.	Entity filing the report include: Company name: Name of contact person: Email address of contact person: Telephone Number: Submitted by (name):		
2.	Date and Time of recognized event. Date: (mm/dd/yyyy) Time: (hh:mm) Time/Zone:		
3.	Did the event originate in your system? Yes <input type="checkbox"/> No <input type="checkbox"/> Unknown <input type="checkbox"/>		
4.	<p style="text-align: center;">Event Identification and Description:</p> <table border="1" style="width: 100%; border-collapse: collapse;"> <tr> <td style="width: 50%; vertical-align: top;"> (Check applicable box) <input type="checkbox"/> Damage or destruction of a Facility <input type="checkbox"/> Physical Threat to a Facility <input type="checkbox"/> Physical Threat to a control center <input type="checkbox"/> BES Emergency: <input type="checkbox"/> public appeal for load reduction <input type="checkbox"/> system-wide voltage reduction <input type="checkbox"/> manual firm load shedding <input type="checkbox"/> automatic firm load shedding <input type="checkbox"/> Voltage deviation on a Facility <input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) <input type="checkbox"/> Loss of firm load <input type="checkbox"/> System separation <input type="checkbox"/> Generation loss <input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply) <input type="checkbox"/> Transmission loss <input type="checkbox"/> unplanned control center evacuation <input type="checkbox"/> Complete loss of voice communication capability <input type="checkbox"/> Complete loss of monitoring capability </td> <td style="width: 50%; vertical-align: top;"> Written description (optional): </td> </tr> </table>	(Check applicable box) <input type="checkbox"/> Damage or destruction of a Facility <input type="checkbox"/> Physical Threat to a Facility <input type="checkbox"/> Physical Threat to a control center <input type="checkbox"/> BES Emergency: <input type="checkbox"/> public appeal for load reduction <input type="checkbox"/> system-wide voltage reduction <input type="checkbox"/> manual firm load shedding <input type="checkbox"/> automatic firm load shedding <input type="checkbox"/> Voltage deviation on a Facility <input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) <input type="checkbox"/> Loss of firm load <input type="checkbox"/> System separation <input type="checkbox"/> Generation loss <input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply) <input type="checkbox"/> Transmission loss <input type="checkbox"/> unplanned control center evacuation <input type="checkbox"/> Complete loss of voice communication capability <input type="checkbox"/> Complete loss of monitoring capability	Written description (optional):
(Check applicable box) <input type="checkbox"/> Damage or destruction of a Facility <input type="checkbox"/> Physical Threat to a Facility <input type="checkbox"/> Physical Threat to a control center <input type="checkbox"/> BES Emergency: <input type="checkbox"/> public appeal for load reduction <input type="checkbox"/> system-wide voltage reduction <input type="checkbox"/> manual firm load shedding <input type="checkbox"/> automatic firm load shedding <input type="checkbox"/> Voltage deviation on a Facility <input type="checkbox"/> IROL Violation (all Interconnections) or SOL Violation for Major WECC Transfer Paths (WECC only) <input type="checkbox"/> Loss of firm load <input type="checkbox"/> System separation <input type="checkbox"/> Generation loss <input type="checkbox"/> Complete loss of off-site power to a nuclear generating plant (grid supply) <input type="checkbox"/> Transmission loss <input type="checkbox"/> unplanned control center evacuation <input type="checkbox"/> Complete loss of voice communication capability <input type="checkbox"/> Complete loss of monitoring capability	Written description (optional):		

Guideline and Technical Basis

Distribution Provider Applicability Discussion

The DSR SDT has included Distribution Providers (DP) as an applicable entity under this standard. The team realizes that not all DPs will own BES Facilities and will not meet the “Threshold for Reporting” for any event listed in Attachment 1. These DPs will not have any reports to submit under Requirement R2. However, these DPs will be responsible for meeting Requirements R1 and R3. The DSR SDT does not intend for these entities to have a detailed Operating Plan to address events that are not applicable to them. In this instance, the DSR SDT intends for the DP to have a very simple Operating Plan that includes a statement that there are no applicable events in Attachment 1 (to meet R1) and that the DP will review the list of events in Attachment 1 each year (to meet R3). The team does not think this will be a burden on any entity as the development and annual validation of the Operating Plan should not take more than 30 minutes on an annual basis. If a DP discovers applicable events during the annual review, it is expected that the DP will develop a more detailed Operating Plan to comply with the requirements of the standard.

Multiple Reports for a Single Organization

For entities that have multiple registrations, the DSR SDT intends that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.

Summary of Key Concepts

The DSR SDT identified the following principles to assist them in developing the standard:

- Develop a single form to report disturbances and events that threaten the reliability of the Bulk Electric System
- Investigate other opportunities for efficiency, such as development of an electronic form and possible inclusion of regional reporting requirements
- Establish clear criteria for reporting
- Establish consistent reporting timelines
- Provide clarity around who will receive the information and how it will be used

During the development of concepts, the DSR SDT considered the FERC directive to “further define sabotage”. There was concern among stakeholders that a definition may be ambiguous and subject to interpretation. Consequently, the DSR SDT decided to eliminate the term sabotage from the standard. The team felt that it was almost impossible to determine if an act or event was sabotage or vandalism without the intervention of law enforcement. The DSR SDT felt that attempting to define sabotage would result in further ambiguity with respect to

reporting events. The term “sabotage” is no longer included in the standard. The events listed in EOP-004 Attachment 1 were developed to provide guidance for reporting both actual events as well as events which may have an impact on the Bulk Electric System. The DSR SDT believes that this is an equally effective and efficient means of addressing the FERC Directive.

The types of events that are required to be reported are contained within EOP-004 Attachment 1. The DSR SDT has coordinated with the NERC Events Analysis Working Group to develop the list of events that are to be reported under this standard. EOP-004 Attachment 1 pertains to those actions or events that have impacted the Bulk Electric System. These events were previously reported under EOP-004-1, CIP-001-1 or the Department of Energy form OE-417. EOP-004 Attachment 1 covers similar items that may have had an impact on the Bulk Electric System or has the potential to have an impact and should be reported.

The DSR SDT wishes to make clear that the proposed Standard does not include any real-time operating notifications for the events listed in EOP-004 Attachment 1. Real-time communication is achieved is covered in other standards. The proposed standard deals exclusively with after-the-fact reporting.

Data Gathering

The requirements of EOP-004-1 require that entities “promptly analyze Bulk Electric System disturbances on its system or facilities” (Requirement R2). The requirements of EOP-004-2 specify that certain types of events are to be reported but do not include provisions to analyze events. Events reported under EOP-004-2 may trigger further scrutiny by the ERO Events Analysis Program. If warranted, the Events Analysis Program personnel may request that more data for certain events be provided by the reporting entity or other entities that may have experienced the event. Entities are encouraged to become familiar with the Events Analysis Program and the NERC Rules of Procedure to learn more about with the expectations of the program.

Law Enforcement Reporting

The reliability objective of EOP-004-2 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.

Stakeholders in the Reporting Process

- Industry

- NERC (ERO), Regional Entity
- FERC
- DOE
- NRC
- DHS – Federal
- Homeland Security- State
- State Regulators
- Local Law Enforcement
- State or Provincial Law Enforcement
- FBI
- Royal Canadian Mounted Police (RCMP)

The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.

Present expectations of the industry under CIP-001-1a:

It has been the understanding by industry participants that an occurrence of sabotage has to be reported to the FBI. The FBI has the jurisdictional requirements to investigate acts of sabotage and terrorism. The CIP-001-1-1a standard requires a liaison relationship on behalf of the industry and the FBI or RCMP. These requirements, under the standard, of the industry have not been clear and have lead to misunderstandings and confusion in the industry as to how to demonstrate that the liaison is in place and effective. As an example of proof of compliance with Requirement R4, Responsible Entities have asked FBI Office personnel to provide, on FBI letterhead, confirmation of the existence of a working relationship to report acts of sabotage, the number of years the liaison relationship has been in existence, and the validity of the telephone numbers for the FBI.

Coordination of Local and State Law Enforcement Agencies with the FBI

The Joint Terrorism Task Force (JTTF) came into being with the first task force being established in 1980. JTTFs are small cells of highly trained, locally based, committed investigators, analysts, linguists, SWAT experts, and other specialists from dozens of U.S. law enforcement and intelligence agencies. The JTTF is a multi-agency effort led by the Justice Department and FBI designed to combine the resources of federal, state, and local law enforcement. Coordination and communications largely through the interagency National Joint Terrorism Task Force, working out of FBI Headquarters, which makes sure that information and intelligence flows freely among the local JTTFs. This information flow can be most beneficial to the industry in analytical intelligence, incident response and investigation. Historically, the most immediate response to an industry incident has been local and state law enforcement agencies to suspected vandalism and criminal damages at industry facilities. Relying upon the JTTF

coordination between local, state and FBI law enforcement would be beneficial to effective communications and the appropriate level of investigative response.

Coordination of Local and Provincial Law Enforcement Agencies with the RCMP

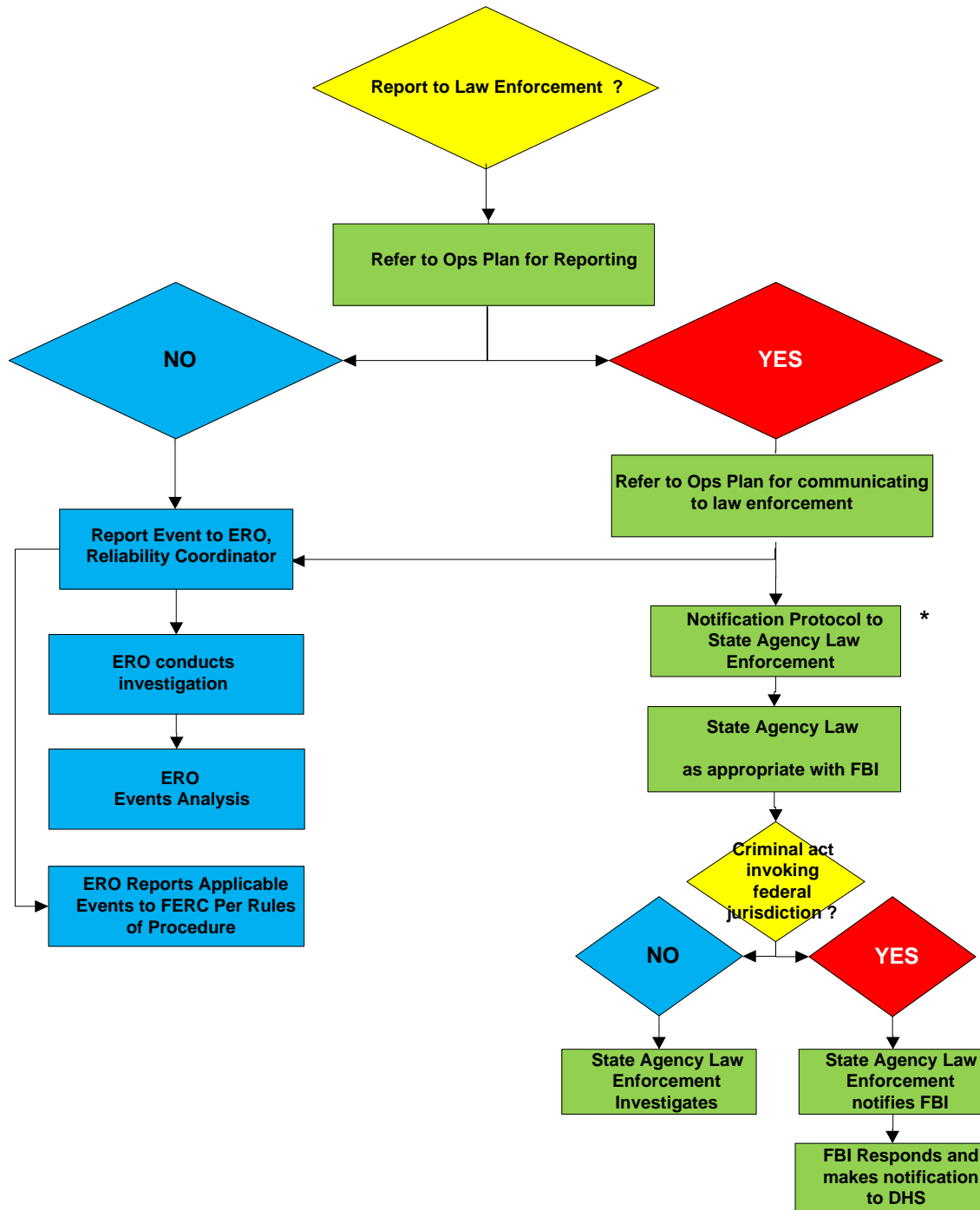
A similar law enforcement coordination hierarchy exists in Canada. Local and Provincial law enforcement coordinate to investigate suspected acts of vandalism and sabotage. The Provincial law enforcement agency has a reporting relationship with the Royal Canadian Mounted Police (RCMP).

A Reporting Process Solution – EOP-004

A proposal discussed with the FBI, FERC Staff, NERC Standards Project Coordinator and the SDT Chair is reflected in the flowchart below (Reporting Hierarchy for Reportable Events). Essentially, reporting an event to law enforcement agencies will only require the industry to notify the state or provincial or local level law enforcement agency. The state or provincial or local level law enforcement agency will coordinate with law enforcement with jurisdiction to investigate. If the state or provincial or local level law enforcement agency decides federal agency law enforcement or the RCMP should respond and investigate, the state or provincial or local level law enforcement agency will notify and coordinate with the FBI or the RCMP.

Example of Reporting Process including Law Enforcement

Entity Experiencing An Event in Attachment 1



* Canadian entities will follow law enforcement protocols applicable in their jurisdictions

Disturbance and Sabotage Reporting Standard Drafting Team (Project 2009-01) - Reporting Concepts

Introduction

The SAR for Project 2009-01, Disturbance and Sabotage Reporting was moved forward for standard drafting by the NERC Standards Committee in August of 2009. The Disturbance and Sabotage Reporting Standard Drafting Team (DSR SDT) was formed in late 2009 and has developed updated standards based on the SAR.

The standards listed under the SAR are:

- CIP-001 — Sabotage Reporting
- EOP-004 — Disturbance Reporting

The changes do not include any real-time operating notifications for the types of events covered by CIP-001 and EOP-004. The real-time reporting requirements are achieved through the RCIS and are covered in other standards (e.g. EOP-002-Capacity and Energy Emergencies). These standards deal exclusively with after-the-fact reporting.

The DSR SDT has consolidated disturbance and sabotage event reporting under a single standard. These two components and other key concepts are discussed in the following sections.

Summary of Concepts and Assumptions:

The Standard:

- Requires reporting of “events” that impact or may impact the reliability of the Bulk Electric System
- Provides clear criteria for reporting
- Includes consistent reporting timelines
- Identifies appropriate applicability, including a reporting hierarchy in the case of disturbance reporting
- Provides clarity around of who will receive the information

Discussion of Disturbance Reporting

Disturbance reporting requirements existed in the previous version of EOP-004. The current approved definition of Disturbance from the NERC Glossary of Terms is:

1. An unplanned event that produces an abnormal system condition.
2. Any perturbation to the electric system.

3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.

Disturbance reporting requirements and criteria were in the previous EOP-004 standard and its attachments. The DSR SDT discussed the reliability needs for disturbance reporting and developed the list of events that are to be reported under this standard (EOP-004 Attachment 1).

Discussion of Event Reporting

There are situations worthy of reporting because they have the potential to impact reliability.

Event reporting facilitates industry awareness, which allows potentially impacted parties to prepare for and possibly mitigate any associated reliability risk. It also provides the raw material, in the case of certain potential reliability threats, to see emerging patterns.

Examples of such events include:

- Bolts removed from transmission line structures
- Train derailment adjacent to a Facility that either could have damaged a Facility directly or could indirectly damage a Facility (e.g. flammable or toxic cargo that could pose fire hazard or could cause evacuation of a control center)
- Destruction of Bulk Electric System equipment

What about sabotage?

One thing became clear in the DSR SDT's discussion concerning sabotage: everyone has a different definition. The current standard CIP-001 elicited the following response from FERC in FERC Order 693, paragraph 471 which states in part: *“. . . the Commission directs the ERO to develop the following modifications to the Reliability Standard through the Reliability Standards development process: (1) further define sabotage and provide guidance as to the triggering events that would cause an entity to report a sabotage event.”*

Often, the underlying reason for an event is unknown or cannot be confirmed. The DSR SDT believes that by reporting material risks to the Bulk Electric System using the event categorization in this standard, it will be easier to get the relevant information for mitigation, awareness, and tracking, while removing the distracting element of motivation.

Certain types of events should be reported to NERC, the Department of Homeland Security (DHS), the Federal Bureau of Investigation (FBI), and/or Provincial or local law enforcement. Other types of events may have different reporting requirements. For example, an event that is related to copper theft may only need to be reported to the local law enforcement authorities.

Potential Uses of Reportable Information

Event analysis, correlation of data, and trend identification are a few potential uses for the information reported under this standard. The standard requires Functional entities to report the incidents and provide known information at the time of the report. Further data gathering necessary for event analysis is provided for under the Events Analysis Program and the NERC Rules of Procedure. Other entities (e.g. – NERC, Law Enforcement, etc) will be responsible for performing the analyses. The [NERC Rules of Procedure \(section 800\)](#) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

Collection of Reportable Information or “One stop shopping”

The DSR SDT recognizes that some regions require reporting of additional information beyond what is in EOP-004. The DSR SDT has updated the listing of reportable events in EOP-004 Attachment 1 based on discussions with jurisdictional agencies, NERC, Regional Entities and stakeholder input. There is a possibility that regional differences still exist.

The reporting required by this standard is intended to meet the uses and purposes of NERC. The DSR SDT recognizes that other requirements for reporting exist (e.g., DOE-417 reporting), which may duplicate or overlap the information required by NERC. To the extent that other reporting is required, the DSR SDT envisions that duplicate entry of information should not be necessary, and the submission of the alternate report will be acceptable to NERC so long as all information required by NERC is submitted. For example, if the NERC Report duplicates information from the DOE form, the DOE report may be sent to the NERC in lieu of entering that information on the NERC report.

Rationale:

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

Rationale for R1:

The requirement to have an Operating Plan for reporting specific types of events provides the entity with a method to have its operating personnel recognize events that affect reliability and to be able to report them to appropriate parties; e.g., Regional Entities, applicable Reliability Coordinators, and law enforcement and other jurisdictional agencies when so recognized. In addition, these event reports are an input to the NERC Events Analysis Program. These other parties use this information to promote reliability, develop a culture of reliability excellence, provide industry collaboration and promote a learning organization.

Every Registered Entity that owns or operates elements or devices on the grid has a formal or informal process, procedure, or steps it takes to gather information regarding what happened when events occur. This requirement has the Responsible Entity establish documentation on

how that procedure, process, or plan is organized. This documentation may be a single document or a combination of various documents that achieve the reliability objective. The communication protocol(s) could include a process flowchart, identification of internal and external personnel or entities to be notified, or a list of personnel by name and their associated contact information. An existing procedure that meets the requirements of CIP-001-2a may be included in this Operating Plan along with other processes, procedures or plans to meet this requirement.

Rationale for R2:

Each Responsible Entity must report and communicate events according to its Operating Plan based on the information in EOP-004-2 Attachment 1. By implementing the event reporting Operating Plan the Responsible Entity will assure situational awareness to the Electric Reliability Organization so that they may develop trends and prepare for a possible next event and mitigate the current event. This will assure that the BES remains secure and stable by mitigation actions that the Responsible Entity has within its function. By communicating events per the Operating Plan, the Responsible Entity will assure that people/agencies are aware of the current situation and they may prepare to mitigate current and further events.

Rationale for R3:

Requirement 3 calls for the Responsible Entity to validate the contact information contained in the Operating Plan each calendar year. This requirement helps ensure that the event reporting Operating Plan is up to date and entities will be able to effectively report events to assure situational awareness to the Electric Reliability Organization. If an entity experiences an actual event, communication evidence from the event may be used to show compliance with the validation requirement for the specific contacts used for the event.

Rationale for EOP-004 Attachment 1:

The DSR SDT used the defined term “Facility” to add clarity for several events listed in Attachment 1. A Facility is defined as:

“A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”

The DSR SDT does not intend the use of the term Facility to mean a substation or any other facility (not a defined term) that one might consider in everyday discussions regarding the grid. This is intended to mean ONLY a Facility as defined above.

Version History

Version	Date	Action	Change Tracking
2		Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting.	Revision to entire standard (Project 2009-01)
2	November 7, 2012	Adopted by the NERC Board of Trustees	
2	June 20, 2013	FERC approved	

Standard EOP-004-2 — Event Reporting

Appendix QC-EOP-004-2 Provisions specific to the standard EOP-004-2 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:** Event Reporting

2. **Number:** EOP-004-2

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

6. **Background:**

No specific provisions

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 Enforcement Processes**

No specific provision

1.4. **Additional Compliance Information**

No specific provisions

Table of Compliance Elements

No specific provision

Standard EOP-004-2 — Event Reporting

Appendix QC-EOP-004-2 Provisions specific to the standard EOP-004-2 applicable in Québec

D. Variances

No specific provision

E. Interpretations

No specific provision

F. References

No specific provision

EOP-004 – Attachment 1: Reportable Events

No specific provision

EOP-004 – Attachment 2: Event reporting Form

No specific provision

Guideline and Technical Basis

No specific provisions

Revision History

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

A. Introduction

1. **Title: Geomagnetic Disturbance Operations**
2. **Number:** EOP-010-1
3. **Purpose:** To mitigate the effects of geomagnetic disturbance (GMD) events by implementing Operating Plans, Processes, and Procedures.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Reliability Coordinator
 - 4.1.2 Transmission Operator with a Transmission Operator Area that includes a power transformer with a high side wye-grounded winding with terminal voltage greater than 200 kV
5. **Background:**

Geomagnetic disturbance (GMD) events have the potential to adversely impact the reliable operation of interconnected transmission systems. During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Protection System Misoperation, the combination of which may result in voltage collapse and blackout.
6. **Effective Date:**

The first day of the first calendar quarter that is six months 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 six months 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 Reliability Coordinator shall develop, maintain, and implement a GMD Operating Plan that coordinates GMD Operating Procedures or Operating Processes within its Reliability Coordinator Area. At a minimum, the GMD Operating Plan shall include:
[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-time Operations]
 - 1.1 A description of activities designed to mitigate the effects of GMD events on the reliable operation of the interconnected transmission system within the Reliability Coordinator Area.
 - 1.2 A process for the Reliability Coordinator to review the GMD Operating Procedures or Operating Processes of Transmission Operators within its Reliability Coordinator Area.

- M1.** Each Reliability Coordinator shall have a current GMD Operating Plan meeting all the provisions of Requirement R1; evidence such as a review or revision history to indicate that the GMD Operating Plan has been maintained; and evidence to show that the plan was implemented as called for in its GMD Operating Plan, such as dated operator logs, voice recordings, or voice transcripts.
- R2.** Each Reliability Coordinator shall disseminate forecasted and current space weather information to functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-time Operations]*
- M2.** Each Reliability Coordinator shall have evidence such as dated operator logs, voice recordings, transcripts, or electronic communications to indicate that forecasted and current space weather information was disseminated as stated in its GMD Operating Plan.
- R3.** Each Transmission Operator shall develop, maintain, and implement a GMD Operating Procedure or Operating Process to mitigate the effects of GMD events on the reliable operation of its respective system. At a minimum, the Operating Procedure or Operating Process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning, Operations Planning, Same-day Operations, Real-Time Operations]*
 - 3.1.** Steps or tasks to receive space weather information.
 - 3.2.** System Operator actions to be initiated based on predetermined conditions.
 - 3.3.** The conditions for terminating the Operating Procedure or Operating Process.
- M3.** Each Transmission Operator shall have a GMD Operating Procedure or Operating Process meeting all the provisions of Requirement R3; evidence such as a review or revision history to indicate that the GMD Operating Procedure or Operating Process has been maintained; and evidence to show that the Operating Procedure or Operating Process was implemented as called for in its GMD Operating Procedure or Operating Process, such as dated operator logs, voice recordings, or voice transcripts.

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 Reliability Coordinator and Transmission Operator 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, Operations Planning, Same-day Operations, Real-time Operations	Medium	The Reliability Coordinator had a GMD Operating Plan, but failed to maintain it.	N/A	The Reliability Coordinator's GMD Operating Plan failed to include one of the required elements as listed in Requirement R1, parts 1.1 or 1.2.	The Reliability Coordinator did not have a GMD Operating Plan OR The Reliability Coordinator failed to implement a GMD Operating Plan within its Reliability Coordinator Area.
R2	Same-day Operations, Real-time Operations	Medium	N/A	N/A	N/A	The Reliability Coordinator failed to disseminate forecasted and current space weather information to all functional entities identified as recipients in the Reliability Coordinator's GMD Operating Plan.
R3	Long-term Planning, Operations Planning,	Medium	The Transmission Operator had a GMD Operating Procedure or Operating Process,	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator's GMD Operating Procedure or Operating Process	The Transmission Operator did not have a GMD Operating Procedure or Operating

EOP-010-1 — Geomagnetic Disturbance Operations

	Same-day Operations, Real-time Operations		but failed to maintain it.	failed to include one of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	failed to include two or more of the required elements as listed in Requirement R3, parts 3.1 through 3.3.	Process OR The Transmission Operator failed to implement its GMD Operating Procedure or Operating Process.
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D. Regional Variances

None.

E. Interpretations

None.

F. Guideline and Technical Basis

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:

An Operating Plan is implemented by carrying out its stated actions.

Coordination is intended to ensure that Operating Procedures are not in conflict with one another. An Operating Plan is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Elements of Requirement R1 take place in various time horizons. Development of the GMD Operating Plan occurs in the Long-Term Planning Time Horizon. Maintenance of the GMD Operating Plan occurs in the Operations Planning Time Horizon. Implementation of the GMD Operating Plan occurs in the Operations Planning, Same-Day and Real-Time Time Horizons.

Rationale for R2:

Requirement R2 replaces IRO-005-3.1a, Requirement R3. IRO-005-4 has been adopted by the NERC Board and filed with FERC, and will retire IRO-005-3.1a Requirement R3. If EOP-010-1 becomes effective prior to the retirement of IRO-005-3.1a, Requirement R2 shall become effective on the first day following retirement of IRO-005-3.1a.

Space weather forecast information can be used for situational awareness and safe posturing of the system. Current space weather information can be used for monitoring progress of a GMD event.

The Reliability Coordinator is responsible for disseminating space weather information to ensure coordination and consistent awareness in its Reliability Coordinator Area.

Rationale for R3:

In developing an Operating Procedure or Operating Process, an entity may consider entity-specific factors such as geography, geology, and system topology.

An Operating Procedure or Operating Process is maintained when it is kept relevant by taking into consideration system configuration, conditions, or operating experience, as needed to accomplish its purpose.

Version History

Version	Date	Action	Change Tracking
1	11/07/2013	Adopted by the NERC Board of Trustees	
1	6/19/2014	FERC Order issued approving EOP-010-1	

Standard EOP-010-1 — Geomagnetic Disturbance Operation

Appendix QC-EOP-010-1 Provisions specific to the standard EOP-010-1 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:** Geomagnetic Disturbance Operation
2. **Number:** EOP-010-1
3. **Purpose:** No specific provision
4. **Applicability:**
No specific provisions
5. **Background:**
No specific provisions
6. **Effective Date:**
 - 6.1. Adoption of the standard by the Régie de l'énergie: Month xx 201x
 - 6.2. Adoption of the appendix by the Régie de l'énergie: Month xx 201x
 - 6.3. 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 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 provisions

Table of Compliance Elements

No specific provision

D. Regional Differences

No specific provision

Standard EOP-010-1 — Geomagnetic Disturbance Operation

Appendix QC-EOP-010-1

Provisions specific to the standard EOP-010-1 applicable in Québec

E. Interpretation

No specific provision

F. Guideline and Technical Basis

No specific provisions

Revision History

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

A. Introduction

1. **Title:** **Facility Connection Requirements**
2. **Number:** FAC-001-1
3. **Purpose:** To avoid adverse impacts on reliability, Transmission Owners and Generator Owners must establish Facility connection and performance requirements.
4. **Applicability:**
 - 4.1. Transmission Owner
 - 4.2. Applicable Generator Owner
 - 4.2.1 Generator Owner with an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems.
5. **Effective Date:**
 - 5.1. In those jurisdictions where regulatory approval is required, all requirements applied to the Transmission Owner become effective upon regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements applied to the Transmission Owner and Regional Entity become effective upon Board of Trustees' adoption.
 - 5.2. In those jurisdictions where regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities. In those jurisdictions where no regulatory approval is required, all requirements applied to the Generator Owner become effective on the first calendar day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

- R1. The Transmission Owner shall document, maintain, and publish Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements. The Transmission Owner's Facility connection requirements shall address connection requirements for:
 - 1.1. Generation Facilities,
 - 1.2. Transmission Facilities, and
 - 1.3. End-user Facilities

[VRF – Medium]
- R2. Each applicable Generator Owner shall, within 45 days of having an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the interconnected Transmission systems (under FAC-002-1), document and publish its Facility connection requirements to ensure compliance with NERC Reliability Standards and applicable Regional Entity, subregional, Power Pool, and individual Transmission Owner planning criteria and Facility connection requirements.

[VRF – Medium]

- R3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall address the following items in its Facility connection requirements:
- 3.1.** Provide a written summary of its plans to achieve the required system performance as described in Requirements R1 or R2 throughout the planning horizon:
- 3.1.1.** Procedures for coordinated joint studies of new Facilities and their impacts on the interconnected Transmission systems.
 - 3.1.2.** Procedures for notification of new or modified Facilities to others (those responsible for the reliability of the interconnected Transmission systems) as soon as feasible.
 - 3.1.3.** Voltage level and MW and MVAR capacity or demand at point of connection.
 - 3.1.4.** Breaker duty and surge protection.
 - 3.1.5.** System protection and coordination.
 - 3.1.6.** Metering and telecommunications.
 - 3.1.7.** Grounding and safety issues.
 - 3.1.8.** Insulation and insulation coordination.
 - 3.1.9.** Voltage, Reactive Power, and power factor control.
 - 3.1.10.** Power quality impacts.
 - 3.1.11.** Equipment Ratings.
 - 3.1.12.** Synchronizing of Facilities.
 - 3.1.13.** Maintenance coordination.
 - 3.1.14.** Operational issues (abnormal frequency and voltages).
 - 3.1.15.** Inspection requirements for existing or new Facilities.
 - 3.1.16.** Communications and procedures during normal and emergency operating conditions.

[VRF – Medium]

- R4.** The Transmission Owner shall maintain and update its Facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Entity, and ERO on request (five business days).

[VRF – Medium]

C. Measures

- M1.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R1.

- M2.** Each Generator Owner that has an executed Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R2.
- M3.** Each Transmission Owner and each applicable Generator Owner (in accordance with Requirement R2) shall make available (to its Compliance Enforcement Authority) evidence that it met all requirements stated in Requirement R3.
- M4.** The Transmission Owner shall make available (to its Compliance Enforcement Authority) evidence that it met all the requirements stated in Requirement R4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Compliance Monitor: Regional Entity

1.2. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

The Transmission Owner 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, Requirement R3, Measure M3, and Requirement R4, Measure M4 from its last audit.

The Generator Owner 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 Generator Owner shall retain evidence of Requirement R2, Measure M2, and Requirement R3, Measure M3 from its last audit.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Not Applicable.	<p>The Transmission Owner failed to do one of the following:</p> <p>Document or maintain or publish Facility connection requirements as specified in the Requirement</p> <p>OR</p> <p>Failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	<p>The Transmission Owner failed to do one of the following:</p> <p>Failed to include (2) of the components as specified in R1.1, R1.2 or R1.3</p> <p>OR</p> <p>Failed to document or maintain or publish its Facility connection requirements as specified in the Requirement and failed to include one (1) of the components as specified in R1.1, R1.2 or R1.3.</p>	The Transmission Owner did not develop Facility connection requirements.
R2	The Generator Owner failed to document and publish Facility connection requirements until more than 45 calendar days but less than or equal to 60 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 60 calendar days but less than or equal to 70 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 70 calendar days but less than or equal to 80 calendar days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.	The Generator Owner failed to document and publish Facility connection requirements until more than 80 days after having an Agreement to evaluate the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the interconnected Transmission systems.
R3	The responsible entity’s Facility	The responsible entity’s Facility	The responsible entity’s Facility	The responsible entity’s Facility

	connection requirements failed to address one of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	connection requirements failed to address two of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	connection requirements failed to address three of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.	connection requirements failed to address four or more of the parts listed in Requirement R3, parts 3.1.1 through 3.1.16.
R4	The responsible entity made the requirements available more than five business days but less than or equal to 10 business days after a request.	The responsible entity made the requirements available more than 10 business days but less than or equal to 20 business days after a request.	The responsible entity made the requirements available more than 20 business days less than or equal to 30 business days after a request.	The responsible entity made the requirements available more than 30 business days after a request.

E. Regional Differences

1. None identified.

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 becomes enforceable on November 25, 2013 for Transmission Owners. For Generator Owners, the standard becomes enforceable on January 1, 2015.	

Standard FAC-001-1 — Facility Connection Requirements

Appendix QC-FAC-001-1 Provisions specific to the standard FAC-001-1 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:** Facility Connection Requirements
2. **Number:** FAC-001-1
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

- R1. No specific provision
- R2. No specific provision
- R3. No specific provision
- R4. The Transmission Owner shall maintain and update its Facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system and the Régie de l'énergie on request (five business days).

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 Process**

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

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

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

Standard FAC-001-1 — Facility Connection Requirements

Appendix QC-FAC-001-1

Provisions specific to the standard FAC-001-1 applicable in Québec

No specific provision

E. Regional Differences

No specific provision

Revision History

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

A. Introduction

1. **Title:** Coordination of Plans For New Generation, Transmission, and End-User Facilities
2. **Number:** FAC-002-1
3. **Purpose:** To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements.
4. **Applicability:**
 - 4.1. Generator Owner
 - 4.2. Transmission Owner
 - 4.3. Distribution Provider
 - 4.4. Load-Serving Entity
 - 4.5. Transmission Planner
 - 4.6. Planning Authority
5. **(Proposed) Effective Date:** The first day of the first calendar quarter six months after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees' adoption.

B. Requirements

- R1. The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:
 - 1.1. Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.
 - 1.2. Ensurance of compliance with NERC Reliability Standards and applicable Regional, subregional, Power Pool, and individual system planning criteria and facility connection requirements.
 - 1.3. Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.
 - 1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.
 - 1.5. Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.
- R2. The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the Regional

Reliability Organization(s) and NERC on request (within 30 calendar days). (Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1.** The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider’s documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard FAC-002-0_R1.
- M2.** The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard FAC-002-0_R2. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

- 1.1. Compliance Enforcement Authority**
Regional Entity.
- 1.2. Compliance Monitoring Period and Reset Timeframe**
Not applicable.
- 1.3. Compliance Monitoring and Enforcement Processes:**
Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints
- 1.4. Data Retention**
Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.
- 1.5. Additional Compliance Information**
None

2. Violation Severity Levels (no changes)

E. Regional Differences

- 1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	January 13, 2006	Removed duplication of “Regional Reliability Organizations(s).	Errata
1	August 5, 2010	Modified to address Order No. 693 Directives	Revised.

Standard FAC-002-1 — Coordination of Plans for New Facilities

		contained in paragraph 693. Adopted by the NERC Board of Trustees.	
1	February 7, 2013	R2 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.	
1	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Standard FAC-002-1 — Coordination of Plans for New Facilities

Appendix QC-FAC-002-1 Provisions specific to the standard FAC-002-1 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:** Coordination of Plans For New Generation, Transmission, and End-User Facilities
2. **Number:** FAC-002-1
3. **Purpose:** No specific provision
4. **Applicability:**
 - Functions**
No specific provision
 - Facilities**
This standard only applies to facilities of the Main Transmission System (RTP).
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

- R1. No specific provision
 - R1.1. No specific provision
 - R1.2. No specific provision
 - R1.3. No specific provision
 - R1.4. Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance under both normal and contingency conditions in accordance with Reliability Standards TPL-001-0.1, TPL-002-0.b, and TPL-003-0.a. For facilities that are not part of the Bulk Power System, compliance with standards TPL-001-0.1, TPL-002-0.b and TPL-003-0.a is not required.
 - R1.5. No specific provision
- R2. No specific provision

C. Measures

Specific provision applicable to measures M1 and M2: the reference to standard FAC-002-0 is replaced by the reference to standard FAC-002-1.

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 Period and Reset Timeframe

No specific provision

1.3. Compliance Monitoring and Enforcement Processes

No specific provision

1.4. Data Retention

No specific provision

1.5. Additional Compliance Information

No specific provision

Standard FAC-002-1 — Coordination of Plans for New Facilities

**Appendix QC-FAC-002-1
Provisions specific to the standard FAC-002-1 applicable in Québec**

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity failed to include in its assessment one of the subcomponents (R1.1 to R1.5).	The responsible entity failed to include in its assessment two of the subcomponents (R1.1 to R1.5).	The responsible entity failed to include in its assessment three of the subcomponents (R1.1 to R1.5).	The responsible entity failed to include in its assessment four of the subcomponents (R1.1 to R1.5).
R1.1.	N/A	N/A	N/A	N/A
R1.2.	N/A	N/A	N/A	N/A
R1.3.	N/A	N/A	N/A	N/A
R1.4.	N/A	N/A	N/A	N/A
R1.5.	N/A	N/A	N/A	N/A
R2.	The responsible entity provided the documentation more than 30 calendar days, but less than or equal to 40 calendar days, after a request.	The responsible entity provided the documentation more than 40 calendar days, but less than or equal to 50 calendar days, after a request.	The responsible entity provided the documentation more than 50 calendar days, but less than or equal to 60 calendar days, after a request.	The responsible entity provided the documentation more than 60 calendar days after a request or was unable to provide the documentation for the required three-year period.

Standard FAC-002-1 — Coordination of Plans for New Facilities

Appendix QC-FAC-002-1

Provisions specific to the standard FAC-002-1 applicable in Québec

E. Regional Differences

No specific provision

Revision History

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

Effective Dates

Generator Owners

There are two effective dates associated with this standard.

The first effective date allows Generator Owners time to develop documented maintenance strategies or procedures or processes or specifications as outlined in Requirement R3.

In those jurisdictions where regulatory approval is required, Requirement R3 applied to the Generator Owner becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirement R3 becomes effective on the first day of the first calendar quarter one year following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

The second effective date allows entities time to comply with Requirements R1, R2, R4, R5, R6, and R7.

In those jurisdictions where regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 applied to the Generator Owner become effective on the first calendar day of the first calendar quarter two years after the date of the order approving the standard from applicable regulatory authorities where such explicit approval for all requirements is required. In those jurisdictions where no regulatory approval is required, Requirements R1, R2, R4, R5, R6, and R7 become effective on the first day of the first calendar quarter two years following Board of Trustees' adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.
3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Transmission Owners [transferred from FAC-003-2]

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

A. Introduction

1. **Title:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.
4. **Applicability**
 - 4.1. **Functional Entities:**
 - 4.1.1. Applicable Transmission Owners
 - 4.1.1.1 Transmission Owners that own Transmission Facilities defined in 4.2.
 - 4.1.2 Applicable Generator Owners
 - 4.1.2.1 Generator Owners that own generation Facilities defined in 4.3
 - 4.2. **Transmission Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal¹, state, provincial, public, private, or tribal entities:
 - 4.2. 1 Each overhead transmission line operated at 200kV or higher.
 - 4.2.2 Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.
 - 4.2.3 Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.
 - 4.2.4 Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.
 - 4.3. **Generation Facilities:** Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal², state, provincial, public, private, or tribal entities:
 - 4.3.1 Overhead transmission lines that (1) extend greater than one mile or 1.609 kilometers beyond the fenced area of the generating station switchyard to the point of interconnection with a Transmission Owner’s Facility or (2) do not have a clear line

¹ EPAAct 2005 section 1211c: “Access approvals by Federal agencies.”

² *Id.*

of sight³ from the generating station switchyard fence to the point of interconnection with a Transmission Owner's Facility and are:

4.3.1.1 Operated at 200kV or higher; or

4.3.1.2 Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or

4.3.1.3 Operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

5. Background:

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

³ "Clear line of sight" means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.

- a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome?*
- b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?*
- c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?*

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

Performance-based: Requirements 1 and 2

Competency-based: Requirement 3

Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

- R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below⁴ [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,⁵
 2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,⁶
 3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage⁷,
 4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.⁸
- M1.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)
- R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below⁹ [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:
1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,¹⁰

⁴ This requirement does not apply to circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the applicable Transmission Owner or applicable Generator Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's or applicable Generator Owner's right to exercise its full legal rights on the ROW.

⁵ If a later confirmation of a Fault by the applicable Transmission Owner or applicable Generator Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

⁶ Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

⁷ *Id.*

⁸ *Id.*

⁹ See footnote 4.

¹⁰ See footnote 5.

2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,¹¹
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,¹²
4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage¹³

M2. Each applicable Transmission Owner and applicable Generator Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each applicable Transmission Owner and applicable Generator Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the applicable Transmission Owner and applicable Generator Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each applicable Transmission Owner and applicable Generator Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the applicable Transmission Owner and applicable Generator Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment *[Violation Risk Factor: Medium] [Time Horizon: Real-time]*.

M4. Each applicable Transmission Owner and applicable Generator Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence

¹¹ See footnote 6.

¹² *Id.*

¹³ *Id.*

may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

- R5.** When a applicable Transmission Owner and applicable Generator Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the applicable Transmission Owner or applicable Generator Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M5.** Each applicable Transmission Owner and applicable Generator Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)
- R6.** Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW¹⁴ [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].
- M6.** Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)
- R7.** Each applicable Transmission Owner and applicable Generator Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

¹⁴ When the applicable Transmission Owner or applicable Generator Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO or GO is granted a time extension that is equivalent to the duration of the time the TO or GO was prevented from performing the Vegetation Inspection.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner¹⁵
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

M7. Each applicable Transmission Owner and applicable Generator Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

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.

For NERC, a third-party monitor without vested interest in the outcome for NERC shall serve as the Compliance Enforcement Authority.

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 Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

¹⁵ Circumstances that are beyond the control of an applicable Transmission Owner or applicable Generator Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or GO or an applicable regulatory body.

The applicable Transmission Owner and applicable Generator Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a applicable Transmission Owner or applicable Generator Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4 Additional Compliance Information

Periodic Data Submittal: The applicable Transmission Owner and applicable Generator Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the applicable Transmission Owner or applicable Generator Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the applicable Transmission Owner or applicable Generator Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an

- IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
 - Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
 - Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
 - Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
 - Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
 - Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by applicable Transmission Owners and applicable Generator Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R2	Real-time	High			<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.</p>	<p>The responsible entity failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:</p> <ul style="list-style-type: none"> • A fall-in from inside the active transmission line

						<p>ROW</p> <ul style="list-style-type: none"> Blowing together of applicable lines and vegetation located inside the active transmission line ROW A grow-in
R3	Long-Term Planning	Lower		The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the responsible entity’s applicable lines. (Requirement R3, Part 3.2)	The responsible entity has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the responsible entity’s applicable lines. Requirement R3, Part 3.1)	The responsible entity does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the responsible entity’s applicable lines.
R4	Real-time	Medium			The responsible entity experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The responsible entity experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The responsible entity did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations	Medium	The responsible entity	The responsible entity failed	The responsible entity failed to	The responsible entity failed to

	Planning		failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The responsible entity failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The responsible entity failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the applicable Transmission Owner or applicable Generator Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

<u>Date that Planning Study is completed</u>	<u>PY the line will become an IROL element</u>	<u>Date 1</u>	<u>Date 2</u>	<u>Effective Date The latter of Date 1 or Date 2</u>
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party

such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by an applicable Transmission Owner or applicable Generator Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the applicable Transmission Owner or applicable Generator Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to include Generator Owners and to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

Explanation for revising the definition of Vegetation Inspections:

The current glossary definition of this NERC term is being modified to include Generator Owners and to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

The Project 2010-07 team further modified that proposed definition to include applicable Generator Owners.

Explanation of the definition of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each applicable Transmission Owner or applicable Generator Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and High for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by an applicable Transmission Owner or applicable Generator Owner or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of

the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of an applicable Transmission Owner or applicable Generator Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with an applicable Transmission Owner's or applicable Generator Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the applicable Transmission Owner or applicable Generator Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the applicable TO or applicable GO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, an applicable Transmission Owner or applicable Generator Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the applicable Transmission Owner or applicable Generator Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the applicable Transmission Owner or applicable Generator Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the applicable Transmission Owner or applicable Generator Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach an

applicable Transmission Owner or applicable Generator Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the applicable Transmission Owner or applicable Generator Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

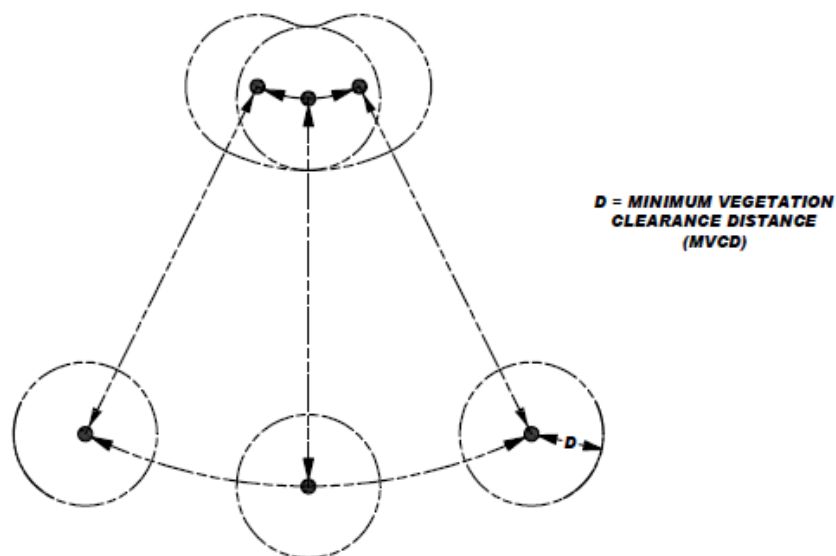


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include

communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of an applicable Transmission Owner or applicable Generator Owner employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The applicable Transmission Owner or applicable Generator Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some applicable Transmission Owners or applicable Generator Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the applicable Transmission Owner or applicable Generator Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the applicable Transmission Owner's or applicable Generator Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the applicable Transmission Owner or applicable Generator Owner is not under any immediate time

constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the applicable Transmission Owner or applicable Generator Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the applicable Transmission Owner or applicable Generator Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the applicable Transmission Owner or applicable Generator Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The applicable Transmission Owner or applicable Generator Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the applicable Transmission Owner or applicable Generator Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the applicable Transmission Owner or applicable Generator Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when an applicable Transmission Owner or applicable Generator Owner operates 2,000 miles of applicable transmission lines this applicable Transmission Owner or applicable Generator Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be $100/2000 = 0.05$ or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:

R7 is a risk-based requirement. The applicable Transmission Owner or applicable Generator Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the applicable Transmission Owner or applicable Generator Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when an applicable Transmission Owner or applicable Generator Owner identifies 1,000 miles of applicable transmission lines to be completed in the applicable Transmission Owner’s or applicable Generator Owner’s annual plan, the applicable Transmission Owner or applicable Generator Owner will be responsible completing those identified miles. If a applicable Transmission Owner or applicable Generator Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: $1000 - 100$ (deferred miles) = 900 modified annual plan, or $900 / 900 = 100\%$ completed annual miles. If an applicable Transmission Owner or applicable Generator Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: $1000 - 875 = 125$ miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the applicable Transmission Owner or applicable Generator Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the applicable Transmission Owner’s or applicable Generator Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the applicable Transmission Owner’s or applicable Generator Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the applicable Transmission Owner or applicable Generator Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Applicable Transmission Owners or applicable Generator Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the applicable Transmission Owner or applicable Generator Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

**FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)¹⁶
For Alternating Current Voltages (feet)**

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV) ¹⁷	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

¹⁶ The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

¹⁷ Where applicable lines are operated at nominal voltages other than those listed, the applicable Transmission Owner or applicable Generator Owner should use the maximum system voltage to determine the appropriate clearance for that line.

**TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)⁷
For Alternating Current Voltages (meters)**

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV) ⁸	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)⁷
For Direct Current Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters	MVCD meters
Over sea level up to 500 ft (Over sea level up to 152.4 m)	Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m)	Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m)	Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m)	Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m)	Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)	
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-

service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:

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

Rationale for Applicability (section 4.2.4):

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for Applicability (section 4.3):

Within the text of NERC Reliability Standard FAC-003-3, “transmission line(s) and “applicable line(s) can also refer to the generation Facilities as referenced in 4.3 and its subsections.

Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of an applicable Transmission Owner's or applicable Generator Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.
2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.
3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.
4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:

The documentation provides a basis for evaluating the competency of the applicable Transmission Owner's or applicable Generator Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the applicable Transmission Owner or applicable Generator Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure

Rationale for R4:

This is to ensure expeditious communication between the applicable Transmission Owner or applicable Generator Owner and the control center when a critical situation is confirmed.

Rationale for R5:

Legal actions and other events may occur which result in constraints that prevent the applicable Transmission Owner or applicable Generator Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the applicable Transmission Owner and applicable Generator Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:

Inspections are used by applicable Transmission Owners and applicable Generator Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable.

Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Version History

Version	Date	Action	Change Tracking
1	TBA	<ol style="list-style-type: none"> 1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer. 	01/20/06
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	
2	March 21, 2013	FERC Order issued approving FAC-003-2	
2	May 9, 2013	Board of Trustees adopted the modification of the VRF for Requirement R2 of FAC-003-2 by raising the VRF from “Medium” to “High.”	
3	May 9, 2012	FAC-003-3 adopted by Board of Trustees	
3	September 19, 2013	A FERC order was issued on September 19, 2013, approving FAC-003-3. This standard becomes enforceable on July 1, 2014 for Transmission Owners. For Generator Owners, R3 becomes enforceable on January 1, 2015 and all other requirements (R1, R2, R4, R5, R6, and R7) will become enforceable on January 1, 2016.	
3	November 22, 2013	Updated the VRF for R2 from “Medium” to “High” per a Final Rule issued by FERC	

3	July 30, 2014	Transferred the effective dates section from FAC-003-2 (for Transmission Owners) into FAC-003-3, per the FAC-003-3 implementation plan	
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Standard FAC-003-3 — Transmission Vegetation Management

Appendix QC-FAC-003-3 Provisions specific to the standard FAC-003-3 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:** Transmission Vegetation Management
2. **Number:** FAC-003-3
3. **Purpose:** No specific provision
4. **Applicability:** No specific provision
5. **Background:** No specific provision
6. **Effective Date:**
 - 6.1. Adoption of the standard by the Régie: Month xx, 201x
 - 6.2. Adoption of the appendix by the Régie: Month xx, 201x
 - 6.3. Effective date of the standard and its appendix in Québec: Month xx, 201x

B. Requirements and Measures

- R1. No specific provision
- R2. No specific provision
- R3. No specific provision
- R4. No specific provision
- R5. No specific provision
- R6. Each applicable Transmission Owner and applicable Generator Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per 2 calendar years where the vegetation control cycle is 5 years or greater, with no more than 36 calendar months between inspections on the same ROW, and at least once per calendar year where the vegetation control cycle is less than 5 years, with no more than 18 calendar months between inspections on the same ROW.
- M6. Each applicable Transmission Owner and applicable Generator Owner has evidence that it conducted Vegetation Inspection of 100% of its applicable transmission lines at least once per 2 calendar years where the vegetation control cycle is 5 years or greater, with no more than 36 calendar months between inspections on the same ROW and at least once per calendar year where the vegetation control cycle is less than 5 years, with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records (R6).
- R7. No specific provision

Standard FAC-003-3 — Transmission Vegetation Management

Appendix QC-FAC-003-3

Provisions specific to the standard FAC-003-3 applicable in Québec

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 Enforcement Processes

No specific provision

1.4. Additional Compliance Information

The periodic data is submitted to the Régie de l'énergie. The Régie de l'énergie will report the information provided quarterly to NERC.

Table of Compliance Elements

No specific provision

D. Regional Differences

No specific provision

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

FAC-003-3 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)

No specific provision

Notes

No specific provision

Rationale

No specific provision

Standard FAC-003-3 — Transmission Vegetation Management

Appendix QC-FAC-003-3

Provisions specific to the standard FAC-003-3 applicable in Québec

Revision History

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

A. Introduction

- 1. Title:** System Operating Limits Methodology for the Planning Horizon
- 2. Number:** FAC-010-2.1
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
 - 4.1. Planning Authority**
- 5. Effective Date:** April 19, 2010

B. Requirements

- R1.** The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:
 - R1.1.** Be applicable for developing SOLs used in the planning horizon.
 - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
 - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
 - R2.1.** In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.
 - R2.2.** Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
 - R2.2.1.** Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
 - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
 - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
 - R2.3.** Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:
 - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

¹ The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard FAC-010-2.1 — System Operating Limits Methodology for the Planning Horizon

- R2.3.2.** System reconfiguration through manual or automatic control or protection actions.
 - R2.4.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.
 - R2.5.** Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
 - R2.6.** In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:
 - R2.6.1.** Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.
- R3.** The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:
 - R3.1.** Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).
 - R3.2.** Selection of applicable Contingencies.
 - R3.3.** Level of detail of system models used to determine SOLs.
 - R3.4.** Allowed uses of Special Protection Systems or Remedial Action Plans.
 - R3.5.** Anticipated transmission system configuration, generation dispatch and Load level.
 - R3.6.** Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.
- R4.** The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:
 - R4.1.** Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.
 - R4.2.** Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.
 - R4.3.** Each Transmission Planner that works in the Planning Authority's Planning Authority Area.
- R5.** If a recipient of the SOL Methodology provides documented technical comments on the methodology, the Planning Authority shall provide a documented response to that recipient within 45 calendar days of receipt of those comments. The response shall indicate whether a change will be made to the SOL Methodology and, if no change will be made to that SOL Methodology, the reason why. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1.** The Planning Authority's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

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- M2.** The Planning Authority shall have evidence it issued its SOL Methodology and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.

If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Planning Authority that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Planning Authority shall self-certify its compliance to the Compliance Monitor at least once every three years. New Planning Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Planning Authority shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

1.4.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

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- 2.1.2** No evidence of responses to a recipient's comments on the SOL Methodology.
(Retirement approved by FERC effective January 21, 2014.)
- 2.2. Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R2.1 through R2.3 and E1.
- 2.3. Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
 - 2.3.1** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
 - 2.3.2** The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
 - 2.3.3** The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.
- 2.4. Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4

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3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.2	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.3.	The Planning Authority has a documented SOL Methodology for use in developing SOLs within its Planning Authority Area, but it does not address R1.1. OR The Planning Authority has no documented SOL Methodology for use in developing SOLs within its Planning Authority Area.
R2	The Planning Authority's SOL Methodology is missing one requirement as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing two requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6	The Planning Authority's SOL Methodology is missing three requirements as described in R2.1, R2.2, R2.3, R2.4, R2.5, or R2.6.	The Planning Authority's SOL Methodology is missing four or more requirements as described in R2.1, R2.2-, R2.3, R2.4, R2.5, or R2.6
R3	The Planning Authority has a methodology for determining SOLs that includes a description for all but one of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but two of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that includes a description for all but three of the following: R3.1 through R3.6.	The Planning Authority has a methodology for determining SOLs that is missing a description of four or more of the following: R3.1 through R3.6.
R4	One or both of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities. For a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change. OR	One of the following: The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change. OR	One of the following: The Planning Authority failed to issue its SOL Methodology and changes to that methodology to more than three of the required entities. The Planning Authority issued its SOL Methodology and changes to that methodology to all but one of the required entities AND for a change in methodology, the changed methodology was

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Requirement	Lower	Moderate	High	Severe
		<p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>	<p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>	<p>provided 90 calendar days or more after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but two of the required entities AND for a change in methodology, the changed methodology was provided 60 calendar days or more, but less than 90 calendar days after the effectiveness of the change.</p> <p>OR</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but three of the required entities AND for a change in methodology, the changed methodology was provided 30 calendar days or more, but less than 60 calendar days after the effectiveness of the change.</p> <p>The Planning Authority issued its SOL Methodology and changes to that methodology to all but four of the required entities AND for a change in methodology, the changed methodology was provided up to 30 calendar days after the effectiveness of the change.</p>
<p>R5 (Retirement)</p>	<p>The Planning Authority received documented technical comments on its SOL Methodology and</p>	<p>The Planning Authority received documented technical comments on its SOL Methodology and</p>	<p>The Planning Authority received documented technical comments on its SOL Methodology and</p>	<p>The Planning Authority received documented technical comments on its SOL Methodology and</p>

Standard FAC-010-2.1 — System Operating Limits Methodology for the Planning Horizon

Requirement	Lower	Moderate	High	Severe
<p>approved by FERC effective January 21, 2014.)</p>	<p>provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>	<p>provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>	<p>provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p>	<p>provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Planning Authority's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p>

E. Regional Differences

- 1.** The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
 - 1.1.** As governed by the requirements of R2.5 and R2.6, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
 - 1.1.1** Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
 - 1.1.2** A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
 - 1.1.3** Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
 - 1.1.4** The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
 - 1.1.5** A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
 - 1.1.6** A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-010.
 - 1.1.7** The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
 - 1.2.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
 - 1.2.1** All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
 - 1.2.2** Cascading does not occur.
 - 1.2.3** Uncontrolled separation of the system does not occur.
 - 1.2.4** The system demonstrates transient, dynamic and voltage stability.
 - 1.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
 - 1.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

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- 1.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
- 1.3.1** Cascading does not occur.
- 1.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
1	November 1, 2006	Fixed typo. Removed the word “each” from the 1 st sentence of section D.1.3, Data Retention.	01/11/07
2	June 24, 2008	Adopted by Board of Trustees; FERC Order 705	Revised
2		Changed the effective date to July 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2.1	November 5, 2009	Adopted by the Board of Trustees — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	April 19, 2010	FERC Approved — errata change Section E1.1 modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2.	Errata
2.1	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	

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2.1	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2.1	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	

Standard FAC-010-2.1 — System Operating Limits Methodology for the Planning Horizon

Appendix QC-FAC-010-2.1

Provisions specific to the standard FAC-010-2.1 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:** System Operating Limits Methodology for the Planning Horizon

2. **Number:** FAC-010-2.1

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 Monitoring Responsibility**

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. **Compliance Monitoring Period and Reset Time Frame**

No specific provision

1.3. **Data Retention**

No specific provision

1.4. **Additional Compliance Information**

No specific provision

2. **Levels of Non-Compliance for Western Interconnection**

No specific provision

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Appendix QC-FAC-010-2.1

Provisions specific to the standard FAC-010-2.1 applicable in Québec

3. Violation Severity Levels

No specific provision

E. Regional Differences

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	May 4, 2015	New appendix	New
1	Month xx, 201x	Modification of the adoption dates	

A. Introduction

- 1. Title:** System Operating Limits Methodology for the Operations Horizon
- 2. Number:** FAC-011-2
- 3. Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
- 4. Applicability**
 - 4.1.** Reliability Coordinator
- 5. Effective Date:** April 29, 2009

B. Requirements

- R1.** The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:
 - R1.1.** Be applicable for developing SOLs used in the operations horizon.
 - R1.2.** State that SOLs shall not exceed associated Facility Ratings.
 - R1.3.** Include a description of how to identify the subset of SOLs that qualify as IROLs.
- R2.** The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following:
 - R2.1.** In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.
 - R2.2.** Following the single Contingencies¹ identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.
 - R2.2.1.** Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.
 - R2.2.2.** Loss of any generator, line, transformer, or shunt device without a Fault.
 - R2.2.3.** Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.
 - R2.3.** In determining the system's response to a single Contingency, the following shall be acceptable:
 - R2.3.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.

¹ The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

C. Measures

- M1. The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.
- M2. The Reliability Coordinator shall have evidence it issued its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with Requirement 4.
- M3. If the recipient of the SOL Methodology provides documented comments on its technical review of that SOL methodology, the Reliability Coordinator that distributed that SOL Methodology shall have evidence that it provided a written response to that commenter within 45 calendar days of receipt of those comments in accordance with Requirement 5. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

1.3. Data Retention

The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology ~~and shall keep all documented comments on its SOL Methodology and associated responses for three years.~~ In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant. (Deleted text retired-Retirement approved by FERC effective January 21, 2014.)

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.4.1 SOL Methodology.

1.4.2 Documented comments provided by a recipient of the SOL Methodology on its technical review of a SOL Methodology, and the associated responses. (Retirement approved by FERC effective January 21, 2014.)

- 1.4.3 Superseded portions of its SOL Methodology that had been made within the past 12 months.
 - 1.4.4 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.
- 2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)**
- 2.1. **Level 1:** There shall be a level one non-compliance if either of the following conditions exists:
 - 2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.
 - 2.1.2 No evidence of responses to a recipient’s comments on the SOL Methodology (Retirement approved by FERC effective January 21, 2014.)
 - 2.2. **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.
 - 2.3. **Level 3:** There shall be a level three non-compliance if any of the following conditions exists:
 - 2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.
 - 2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.
 - 2.3.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.
 - 2.4. **Level 4:** The SOL Methodology was not issued to all required entities in accordance with R4.

3. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	Not applicable.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.	The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1. OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.
R2	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)	Not applicable.	The Reliability Coordinator's SOL Methodology requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)	The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)
R3	The Reliability Coordinator's SOL Methodology includes a description for all but one of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but two of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology includes a description for all but three of the following: R3.1 through R3.7.	The Reliability Coordinator's SOL Methodology is missing a description of four or more of the following: R3.1 through R3.7.
R3.6	N/A	N/A	N/A	N/A
R4	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to one of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to two of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4.1, R4.2, and R4.3.	The Reliability Coordinator failed to issue its SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4.1, R4.2, and R4.3

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Requirement	Lower	Moderate	High	Severe
	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no more than 10 calendar days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of required entities more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 days after the effectiveness of the change.</p>	<p>OR</p> <p>For a change in methodology, the changed methodology was provided to one or more of the required entities more than 30 calendar days after the effectiveness of the change.</p>
<p>R5 (Retirement approved by FERC effective January 21, 2014.)</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was longer than 45 calendar days but less than 60 calendar days.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 60 calendar days or longer but less than 75 calendar days.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 75 calendar days or longer but less than 90 calendar days.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology indicated that a change will not be made, but did not include an explanation of why the change will not be made.</p>	<p>The Reliability Coordinator received documented technical comments on its SOL Methodology and provided a complete response in a time period that was 90 calendar days or longer.</p> <p>OR</p> <p>The Reliability Coordinator's response to documented technical comments on its SOL Methodology did not indicate whether a change will be made to the SOL Methodology.</p>

Regional Differences

1. The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:
 - 1.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:
 - 1.1.1 Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.
 - 1.1.2 A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7
 - 1.1.3 Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.
 - 1.1.4 The failure of a circuit breaker associated with a Special Protection System to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.
 - 1.1.5 A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.
 - 1.1.6 A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.
 - 1.1.7 The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.
 - 1.2. SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:
 - 1.2.1 All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.
 - 1.2.2 Cascading does not occur.
 - 1.2.3 Uncontrolled separation of the system does not occur.
 - 1.2.4 The system demonstrates transient, dynamic and voltage stability.
 - 1.2.5 Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.
 - 1.2.6 Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

- 1.2.7 To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
- 1.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:
 - 1.3.1 Cascading does not occur.
- 1.4. The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed “Cascading Outage” to “Cascading” Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	

Standard FAC-011-2 — System Operating Limits Methodology for the Operations Horizon

Appendix QC-FAC-011-2

Provisions specific to the standard FAC-011-2 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:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-2
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 Monitoring Responsibility

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. Compliance Monitoring Period and Reset Time Frame

No specific provision

1.3. Data Retention

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Levels of Non-Compliance

No specific provision

Standard FAC-011-2 — System Operating Limits Methodology for the Operations Horizon

Appendix QC-FAC-011-2

Provisions specific to the standard FAC-011-2 applicable in Québec

3. Violation Severity Levels

All occurrences of the term “BES” are replaced by “RTP”.

E. Regional Differences

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	May 4, 2015	New appendix	New
1	Month xx, 201x	Modification of adoption dates	

A. Introduction

1. **Title:** **Dynamic Transfers**
2. **Number:** INT-004-3
3. **Purpose:** To ensure Dynamic Schedules and Pseudo-Ties are communicated and accounted for appropriately in congestion management procedures.

4. **Applicability:**

- 4.1. Balancing Authority
- 4.2. Purchasing-Selling Entity

5. **Effective Date:**

First day of the second calendar quarter 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 six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to ensure the transparency of Dynamic Transfers.

- R1 is modified from Requirement R1 of INT-001-3 and transferred into INT-004-3. The revised requirement now includes Pseudo-Ties.
- R2 is modified from INT-004-2 to separate the triggers for the review of the Dynamic Transfer and when a modification is required for the Dynamic Transfer.
- R1 and R2 now also apply to Pseudo-Ties. The requirements to create an RFI for Pseudo-Ties ensure that all entities involved are aware of the Dynamic Transfer and agree that the various responsibilities associated with the dynamic transfer have been agreed upon.
- R3 is created to ensure that coordination occurs between all entities involved prior to the initial implementation of a Pseudo-Tie.
- The Guidelines and Technical Basis section was added to provide a summary of the considerations that must be given when establishing any Dynamic Transfer.

B. Requirements and Measures

- R1.** Each Purchasing-Selling Entity that secures energy to serve Load via a Dynamic Schedule or Pseudo-Tie shall ensure that a Request for Interchange is submitted as an on-time¹ Arranged Interchange to the Sink Balancing Authority for that Dynamic Schedule or Pseudo-Tie, unless the information about the Pseudo-Tie is included in congestion management procedure(s) via an alternate method. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same-day Operations*]
- M1.** The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs or other evidence) that a Request for Interchange was submitted for Dynamic Schedules and Pseudo-Ties as an on-time Arranged Interchange to the Sink Balancing Authority for the Dynamic Schedule or Pseudo-Tie. For Pseudo-Ties included in congestion management procedure(s) via an alternate method, the Purchasing-Selling Entity shall have evidence such as Interchange Distribution Calculator model data or written / electronic agreement with a Balancing Authority to include the Pseudo-Tie in the congestion management procedure(s). (R1)
- R2.** The Purchasing-Selling Entity that submits a Request for Interchange in accordance with Requirement R1 shall ensure the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie is updated for future hours in order to support congestion management procedures if any one of the following occurs: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning, Same Day Operations, Real Time Operations*]
- 2.1.** For Confirmed Interchange greater than 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 10% for that hour and that deviation is expected to persist.
- 2.2.** For Confirmed Interchange less than or equal to 250 MW for the last hour, the actual hourly integrated energy deviates from the Confirmed Interchange by more than 25 MW for that hour and that deviation is expected to persist.
- 2.3.** The Purchasing-Selling Entity receives notification from a Reliability Coordinator or Transmission Operator to update the Confirmed Interchange.
- M2.** The Purchasing-Selling Entity shall have evidence (such as dated and time-stamped electronic logs, reliability studies or other evidence) that it updated its Confirmed Interchange Requests for Interchange when the deviation met the criteria in Requirement R2, Parts 2.1- 2.3. (R2)
- R3.** Each Balancing Authority shall only implement or operate a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication in order to support

¹ Please refer to the timing tables of INT-006-4.

congestion management procedures. [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

- M3.** The Balancing Authority shall have evidence (such as dated and time-stamped electronic logs or other evidence) that it only implemented or operated a Pseudo-Tie that is included in the NAESB Electric Industry Registry publication. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Purchasing-Selling Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. 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 Purchasing-Selling Entity shall maintain evidence to show compliance with R1 and R2 for the most recent 3 calendar months plus the current month.
- The Balancing Authority shall maintain evidence to show compliance with R3 for the most recent 3 calendar months plus the current month.

If a Purchasing-Selling Entity or Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. 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	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	The Purchasing-Selling Entity secured energy to serve Load via a Dynamic Schedule or Pseudo-Tie, but did not ensure that a Request for Interchange was submitted as on-time Arranged Interchange to the Sink Balancing Authority, and did not include information about the Pseudo-Tie in congestion management procedure(s) via an alternate method.
R2	Operations Planning, Same Day Operations	Lower	N/A	N/A	N/A	A deviation met or exceeded the criteria in Requirement R2 Parts 2.1- 2.3 and was expected to persist, but the Purchasing-Selling Entity did not ensure that the Confirmed Interchange associated with that Dynamic Schedule or Pseudo-Tie was updated for future hours.

Standard INT-004-3 — Dynamic Transfers

R3	Operations Planning	Lower	N/A	N/A	N/A	The Balancing Authority implemented or operated a Pseudo-Tie that was not included in the NAESB Electric Industry Registry publication.
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D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

The complete Dynamic Transfer Reference Guidelines document is included in the NERC Operating Manual at:
http://www.nerc.com/files/opman_3_2012.pdf.

Application Guidelines

Guidelines and Technical Basis

This standard requires the submittal of an Arranged Interchange for both Dynamic Schedules and Pseudo-Ties. In general, Pseudo-Ties are accounted for by all parties as actual Interchange and Dynamic Schedules are accounted for as Scheduled Interchange. The obligations of the entities involved in each type of Dynamic Transfer are dependent on the type of Dynamic Transfer selected. These guidelines provide items that should be considered when determining which type of Dynamic Transfer should be utilized for a given situation.

General Considerations When Establishing and Implementing Dynamic Transfers:

- During the setup of a Dynamic Transfer, a common source of data is established. During that setup, plans should also be established for what will occur when that normal source of data is not available.
- Following any reliability adjustments to a Dynamic Schedule, each Balancing Authority shall use agreed upon values that ensure any limit established by the reliability adjustment is not exceeded.
 - Since the Net Scheduled Interchange term used in its control ACE (or alternate control process) is not the value from the Confirmed Interchange, but from some common source, each Balancing Authority must be prepared to take action to control the data feeding that common source.
- Each Attaining Balancing Authority shall incorporate resources attained via Dynamic Schedules or Pseudo-Ties into its processes for establishing Contingency Reserve requirements, as well as for the purposes of measuring Contingency Reserve response.

The table below describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedules related to many of the topics addressed above. In practical application, however, both the Native Balancing Authority and Attaining Balancing Authority can agree to exchange the obligations from that shown in the table below.

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be re-assigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery /reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services FERC OATT Schedules 3–6 and other ancillary services	Attaining BA	Native BA

Application Guidelines

as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE Frequency Bias calc/setting	The Native and Attaining BA(s) shall adjust the control logic that determines their Frequency Bias Setting to account for the Frequency Bias characteristics of the loads and/or resources being assigned between BA(s) by the Pseudo-Tie	The Attaining BA should include the Load from its Dynamic Schedule as a part of its forecast load to set Frequency Bias requirement. The Native BA should change its Load used to set Frequency Bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert (EEA)	Attaining BA	Native BA

General Considerations for Curtailments of Dynamic Transfers

The unique handling of curtailments of Dynamic Transfers is described in NERC’s Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.

For Pseudo-Ties:

If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Application Guidelines

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the curtailment.

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 R1:

This Requirement is intended to ensure that an RFI is submitted for a Dynamic Schedule or Pseudo-Tie. If a forecast is available, it is expected that the forecast will be used to indicate the energy profile on the RFI. If no forecast is available, the energy profile cannot exceed the maximum expected transaction MW amount.

Rationale R2:

This requirement does not preclude tags from being updated at any time. The requirement specifies conditions under which the tag must be updated.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	October 9, 2007	Adopted by the NERC Board of Trustees (Removal of WECC Waiver)	Revised
2	July 21, 2008	Approved by FERC	Revised
3	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
3	June 30, 2014	FERC letter order issued approving INT-004-3	

Standard INT-004-3 — Dynamic Transfers

Appendix QC-INT-004-3

Provisions specific to the standard INT-004-3 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:** Dynamic Transfers
2. **Number:** INT-004-3
3. **Purpose:** No specific provision
4. **Applicability:**

Functions

This standard does not apply to Purchase-Selling Entities.

Facilities

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 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. **Table of Compliance Elements**

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

Standard INT-004-3 — Dynamic Transfers

Appendix QC-INT-004-3

Provisions specific to the standard INT-004-3 applicable in Québec

No specific provision

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

Rationale

No specific provision

Version History

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New

A. Introduction

1. **Title:** Evaluation of Interchange Transactions
2. **Number:** INT-006-4
3. **Purpose:** To ensure that responsible entities conduct a reliability assessment of each Arranged Interchange before it is implemented.
4. **Applicability:**
 - 4.1. Balancing Authority
 - 4.2. Transmission Service Provider

5. **Effective Date:**

First day of the second calendar quarter 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 six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-006-4 continues to be the reliability assessment of Interchange Transactions prior to their implementation.

The content of INT-006-4 has been revised and expanded in the following manner:

- R1 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Balancing Authority must deny the transition.
- R2 was created by revising R1 from INT-006-3. This requirement ensures that Transmission Service Providers involved in an Arranged Interchange actively approve or deny the transition to Confirmed Interchange. The requirement also lists criteria to determine when a Transmission Service Provider must deny the transition.
- R3 was created by revising R1 from INT-006-3. This requirement ensures that Balancing Authorities who receive a Reliability Adjustment Arranged Interchange actively approve or deny the transition to Confirmed Interchange.
- R4 was created by moving and revising R1 from INT-007-1, which has been retired as part of the project. This requirement lists criteria for when a Sink Balancing Authority shall not transition an Arranged Interchange to Confirmed Interchange.

- R5 was created by moving and revising R1 from INT-008-3, which has been retired as part of the project. This requirement lists the entities to which a Sink Balancing Authority must distribute notifications of whether an Arranged Interchange has transitioned to Confirmed Interchange.
- Attachment 1 timing tables for WECC were modified to address scheduling on a 15 minute basis.

Requirements and Measures

- R1.** Each Balancing Authority shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*
- 1.1.** Each Source and Sink Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if it does not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout the duration of the Arranged Interchange.
- 1.2.** Each Balancing Authority shall deny the Arranged Interchange or curtail Confirmed Interchange if the Scheduling Path (proper connectivity of Adjacent Balancing Authorities) between it and its Adjacent Balancing Authorities is invalid.
- M1.** Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it responded to each request for its approval to transition an Arranged Interchange to a Confirmed Interchange within the time defined in Attachment 1, Column B. (R1)
- R2.** Each Transmission Service Provider shall approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives and shall do so prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*
- 2.1.** Each Transmission Service Provider shall deny the Arranged Interchange or curtail Confirmed Interchange if the transmission path (proper connectivity of adjacent Transmission Service Providers) between it and its adjacent Transmission Service Providers is invalid.
- M2.** Each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it responded to each Arranged Interchange or emergency Arranged Interchange within the time defined in Attachment 1, Column B. If the transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers is invalid, each Transmission Service Provider shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that it denied the Arranged Interchange or curtailed confirmed Interchange. (R2)

- R3.** The Source Balancing Authority and the Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange shall approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*
- 3.1.** If a Balancing Authority denies a Reliability Adjustment Arranged Interchange, the Balancing Authority must communicate that fact to its Reliability Coordinator no more than 10 minutes after the denial.
- M3.** Each Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that when responding to a Reliability Adjustment Arranged Interchange, it either approved the request or denied the request and, if applicable, communicated denial to the Reliability Coordinator no more than 10 minutes after the denial. (R3)
- R4.** Each Sink Balancing Authority shall confirm that none of the following conditions exist prior to transitioning an Arranged Interchange to Confirmed Interchange: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*
- It is a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B has elapsed, and the Source Balancing Authority or the Sink Balancing Authority associated with the Arranged Interchange has not communicated its approval of the transition.
 - It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and not all Balancing Authorities and Transmission Service Providers associated with the Arranged Interchange have communicated their approval of the transition.
 - It is not a Reliability Adjustment Arranged Interchange, the time period specified in Attachment 1, Column B, has elapsed, and any entity associated with the Arranged Interchange has communicated its denial of the transition.
- M4.** Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, studies, or other evidence) that, under the conditions in R4, it did not transition an Arranged Interchange to Confirmed Interchange. (R4)
- R5.** For each Arranged Interchange that is transitioned to Confirmed Interchange, the Sink Balancing Authority shall notify the following entities of the on-time Confirmed Interchange such that the notification is delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*
- 5.1.** The Source Balancing Authority,
- 5.2.** Each Intermediate Balancing Authority,

- 5.3. Each Reliability Coordinator associated with each Balancing Authority included in the Arranged Interchange,
 - 5.4. Each Transmission Service Provider included in the Arranged Interchange, and
 - 5.5. Each Purchasing Selling Entity included in the Arranged Interchange.
- M5. Each Sink Balancing Authority shall have evidence (such as dated and time stamped electronic logs, or other evidence) that it notified the entities of the on-time Confirmed Interchange such that the notification was delivered in time to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D. (R5)

B. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For 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 Balancing Authority shall maintain evidence to show compliance with R1, R3, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R2 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	N/A	<p>The Balancing Authority receiving an on-time Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.</p> <p>OR</p> <p>The Source or Sink Balancing Authority did not expect to be capable of supporting the magnitude of the Interchange, including ramping, throughout duration of the Arranged Interchange and did not deny the Arranged Interchange or curtail Confirmed Interchange.</p> <p>OR</p> <p>The Scheduling Path between the Balancing Authority and its Adjacent Balancing Authorities was invalid, and the Balancing Authority did not deny the Arranged Interchange or curtail Confirmed Interchange.</p>
R2	Operations Planning,	Lower	N/A	N/A	N/A	<p>The Transmission Service Provider receiving an on-time</p>

Standard INT-006-4 — Evaluation of Interchange Transactions

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Same-day Operations, Real-time Operations					<p>Arranged Interchange or an emergency Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.</p> <p>OR</p> <p>The transmission path between the Transmission Service Provider and its adjacent Transmission Service Providers was invalid, and the Transmission Service Provider did not deny the Arranged Interchange or curtail Confirmed Interchange.</p>
R3	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange denied it prior to the expiration of the time period defined in Attachment 1, Column B, but did not communicate that fact to its Reliability Coordinator within 10 minutes of the denial.	The Source Balancing Authority or Sink Balancing Authority receiving a Reliability Adjustment Arranged Interchange did not approve or deny it prior to the expiration of the time period defined in Attachment 1, Column B.
R4	Operations Planning, Same-day Operations,	Lower	N/A	N/A	N/A	The Sink Balancing Authority failed to confirm that none of the conditions in Requirement 4 existed before transitioning

Standard INT-006-4 — Evaluation of Interchange Transactions

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
	Real-time Operations					an Arranged Interchange to Confirmed Interchange.
R5	Operations Planning, Same-day Operations, Real-time Operations	Lower	N/A	N/A	The Sink Balancing Authority did not notify all of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.	<p>The Sink Balancing Authority did not notify any of the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange.</p> <p>OR</p> <p>The Sink Balancing Authority notified the entities listed in Requirement R5 Parts 5.1-5.5 of the on-time Confirmed Interchange, but did not notify one or more of the entities in time for the notification to be incorporated into scheduling systems prior to ramp start as specified in Attachment 1, Column D.</p>

C. Regional Variances

None.

D. Interpretations

None.

E. Associated Documents

None.

Attachment 1 – Timing Tables

Timing Requirements for all Interconnections except WECC

		A	B	C	D
If Arranged Interchange ¹ is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange ²	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status ²	BA Prepares Confirmed Interchange for Implementation
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<15 minutes prior to ramp start and ≤1 hour after the start time	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥1 hour to < 4 hours prior to ramp start	On-time		≤ 20 minutes from Arranged Interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start

¹ Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

² See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Attachment 1 – Timing Tables

Timing Requirements for WECC

		A	B	C	D
If Arranged Interchange ³ is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange ⁴	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status ⁴	BA Prepares Confirmed Interchange for Implementation
>1 hour after the start time	ATF		Entities have up to 2 hours to respond.		NA
<10 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is at the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
<15 minutes prior to ramp start and ≤1 hour after transaction start time where transaction start time is not the top of the hour	Late		Entities have up to 10 minutes to respond.		≤ 3 minutes after receipt of Confirmed Interchange
10 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 5 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
11 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 6 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start

³ Time Classifications and deadlines apply to both initial Arranged Interchange submittal and any subsequent modifications to the Arranged Interchange.

⁴ See NAESB WEQ004. The times are being retained in the NAESB tables but are removed here since they are not being referenced in requirements.

Standard INT-006-4 — Evaluation of Interchange Transactions

		A	B	C	D
If Arranged Interchange³ is Submitted	Time Classification	Sink BA Makes Initial Distribution of Arranged Interchange⁴	BA and TSP Conduct Reliability Assessments	Compilation and Distribution Status⁴	BA Prepares Confirmed Interchange for Implementation
12 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 7 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
13 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 8 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
14 minutes prior to ramp start where transaction start time is at the top of the hour	On-time		≤ 9 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
<1 hour and ≥ 15 minutes prior to ramp start	On-time		≤ 10 minutes from Arranged Interchange receipt		≥ 3 minutes prior to ramp start
≥ 1 hour and < 4 hours prior to ramp start	On-time		< 20 minutes from Arranged interchange receipt		≥ 39 minutes prior to ramp start
≥ 4 hours prior to ramp start	On-time		≤ 2 hours from Arranged Interchange receipt		≥ 1 hour 58 minutes prior to ramp start
Submitted before 10:00 PPT with start time ≥ 00:00 PPT of following day	On-time		By 12:00 PPT of day the Arranged Interchange was received		≥ 1 hour 58 minutes prior to ramp start

Application Guidelines

Guidelines and Technical Basis

Many aspects of managing Interchange are supported by software applications. There are fundamental tasks that each entity should be able to perform in an electronic manner as listed below.

A Load-Serving Entity and Balancing Authority that submits Requests for Interchange should have the capability to electronically:

- Submit a Request for Interchange to a Sink Balancing Authority
- Submit a request to modify Interchange
- Receive distributions of Confirmed Interchange
- Receive distributions of Reliability Adjustment Arranged Interchanges

Each Sink Balancing Authority should have the capability to electronically:

- Receive a Request for Interchange
- Receive a request to modify Interchange
- Validate Requests for Interchange by verifying:
 - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
 - All reliability entities involved in the Arranged Interchange are valid.
 - Generation source and Load sink are defined.
 - Megawatt profile is defined.
 - Interchange duration is defined.
- Validate request to modify Interchange by verifying:
 - Source Balancing Authority megawatts equal Sink Balancing Authority megawatts (adjusted for losses, if appropriate).
 - Megawatt profile is defined.
 - Interchange duration is defined.
- Distribute the validated Request for Interchange as Arranged Interchange
- Distribute the validated Reliability Adjustment Arranged Interchanges
- Receive communication of approval or denial of Arranged Interchange
 - Distribute notification as each entity approves or denies an Arranged Interchange.
 - Transition Arranged Interchange to Confirmed Interchange if all approvals are received.
 - Distribute notification of whether Arranged Interchange was transitioned to Confirmed Interchange or not.

Application Guidelines

- Submit a request to modify Interchange
- Each Load-Serving Entity that approves or denies Arranged Interchange, and each Balancing Authority and Transmission Service Provider should have the capability to electronically:
 - Receive distribution of Arranged Interchange
 - Communicate approval or denial of the Arranged Interchange to the Sink Balancing Authority
 - Receive notification of whether Arranged Interchange was transitioned to Confirmed interchange or not.
 - Submit a request to modify Interchange
- While Interchange is normally facilitated using electronic communication and software tools, there are occasions with those electronic capabilities are reduced or unavailable. It is recommended that all entities involved in aspects of Interchange should have, maintain and implement a plan describing the manner and timing in which all capabilities listed above will be provided when electronic capabilities are reduced or unavailable. Each plan should address the following topics:
 - Alternate methods of communicating Interchange information between Purchasing Selling Entities, Balancing Authorities, and Transmission Service Providers.
 - How to notify others that it is activating the plan
 - How it will process requests for emergency Arranged Interchange and Reliability Adjustment Arranged Interchange.
 - Restrictions and limitations that may apply during the period of reduced or unavailable capability (such as limits on volume, only accepting emergency transactions, etc.).
 - Delegation of approval rights and proxy actions, if such approaches will be used.
 - How known Confirmed Interchange will be scheduled following a reduction in or loss of capability.
 - Personnel plans for short-term and extended periods.
 - Training of personnel in the use of the plan.

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:

Balancing Authorities must take action on a received Arranged Interchange within a certain time frame. Requirement R1, Parts 1.1 and 1.2 provide reliability-related reasons that a Balancing

Application Guidelines

Authority must deny an Arranged Interchange, but Balancing Authorities may deny for other reasons. If the conditions described in Requirement R1, Parts 1.1 or 1.2 are recognized after approval is granted, the Balancing Authority may curtail the Confirmed Interchange prior to implementation.

Rationale for R2:

TSPs must take action on a received Arranged Interchange within a certain time frame. Requirement R2, Part 2.1 provides reliability-related reasons that a TSP must deny an Arranged Interchange, but TSPs may deny for other reasons. If the conditions described in Requirement R1, Part 2.1 are recognized after approval is granted, the TSP may curtail the Confirmed Interchange prior to implementation.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Adopted by the NERC Board Of Trustees	New
2	May 2, 2007	Adopted by the NERC Board Of Trustees	Revised
3	October 29, 2008	Adopted by the NERC Board Of Trustees	Revised
3	July 1, 2010	Approved by FERC	Revised
4	February 6, 2014	Adopted by the NERC Board Of Trustees	Revised
4	June 30, 2014	FERC letter order issued approving INT-006-4	

Standard INT-006-4 — Evaluation of Interchange Transactions

Appendix QC-INT-006-4

Provisions specific to the standard INT-006-4 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:** Evaluation of Interchange Transactions
2. **Number:** INT-006-4
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: Month xx, 201x
6. **Background:** No specific provision

Requirements and Measures

No specific provision

B. 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

Table of compliance elements

No specific provision

C. Regional Variances

No specific provision

D. Interpretations

No specific provision

Standard INT-006-4 — Evaluation of Interchange Transactions

Appendix QC-INT-006-4

Provisions specific to the standard INT-006-4 applicable in Québec

E. Associated Documents

No specific provision

Attachment 1- Timing Tables

No specific provision

Guidelines and technical basis

No specific provision

Revision History

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

A. Introduction

1. **Title:** **Implementation of Interchange**
2. **Number:** **INT-009-2**
3. **Purpose:** To ensure that Balancing Authorities implement the Interchange as agreed upon in the Interchange confirmation process.
4. **Applicability:**
 - 4.1. Balancing Authority.
5. **Effective Date:**

The first day of the first calendar quarter that is six months 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 six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards effort to combine requirements from the various INT standards into a fewer number of standards and in a logical sequence. The focus of INT-009-2 continues to be the Balancing Authority to Balancing Authority Interchange confirmation process for Interchange Transactions prior to their implementation.

The Requirements in INT-009-2 have been expanded to include previous Measures from INT-009-1 and acknowledge Dynamic Schedules and Pseudo-Ties. A new term “Composite Confirmed Interchange” has been introduced.

The content of INT-009-2 has been revised and expanded in the following manner:

- R1 was combined with INT-003-3 R1 and modified to ensure that a Balancing Authority agrees to a Composite Confirmed Interchange with each of its Adjacent Balancing Authorities.
- R2 was created to ensure that Adjacent Balancing Authorities incorporating a Pseudo-Tie agree to a common source for their Actual Net Interchange term for their ACE controls.
- R3 was created by revising R1.2 from INT-003-3. This requirement ensures that the Balancing Authority that controls a high-voltage direct current tie coordinates the Confirmed Interchange.

B. Requirements and Measures

- R1.** Each Balancing Authority shall agree with each of its Adjacent Balancing Authorities that its Composite Confirmed Interchange with that Adjacent Balancing Authority, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange, is: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- 1.1.** Identical in magnitude to that of the Adjacent Balancing Authority, and
 - 1.2.** Opposite in sign or direction to that of the Adjacent Balancing Authority.
- M1.** The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, or other evidence) that its Composite Confirmed Interchange, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange as directed per INT-010-2 not yet captured in the Composite Confirmed Interchange, was agreed to by each Adjacent Balancing Authority, identical in magnitude to those of each Adjacent Balancing Authority, and opposite in sign to that of each Adjacent Balancing Authority. (R1)
- R2.** The Attaining Balancing Authority and the Native Balancing Authority shall use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- M2.** The Balancing Authority shall have evidence (such as dated logs, voice recordings, electronic records, written agreement or other evidence) that it used a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI_A) term of their respective control ACE (or alternate control process). (R2)
- R3.** Each Balancing Authority in whose area the high-voltage direct current tie is controlled shall coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations, Operations Planning*]
- M3.** The Balancing Authority shall have evidence (such as dated logs, electronic records, or other evidence) that it coordinated the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. 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 Balancing Authority shall maintain evidence to show compliance with R1, R2 and R3 for the most recent 3 months plus the current month.

If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority did not reach agreement with an Adjacent Balancing Authority on the magnitude or sign of its Composite Confirmed Interchange, at mutually agreed upon time intervals, excluding Dynamic Schedules and Pseudo-Ties and including any Interchange per INT-010-2 not yet captured in the Composite Confirmed Interchange.
R2	Real-time Operations	Medium	N/A	N/A	N/A	The Balancing Authority failed to use a dynamic value emanating from an agreed upon common source to account for the Pseudo-Tie in the Actual Net Interchange (NI _A) term of their respective control ACE (or alternate control process).
R3	Real-time Operations, Operations Planning	Medium	N/A	N/A	N/A	The Balancing Authority failed to coordinate the Confirmed Interchange prior to its implementation with the Transmission Operator of the high-voltage direct current tie.

Application Guidelines

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

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 R2: R12.3 of BAL-005-2b addresses common metering for Dynamic Schedules and Pseudo-Ties but not their implementation into ACE. Requirement R2 is parallel to R10 of BAL-005-2b which only addresses Dynamic Schedules. Presently, there is a gap in the BAL standards that this requirement fills for Pseudo-Ties.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	May 2, 2006	Adopted by the NERC Board of Trustees	Revised
2	February 6, 2014	Adopted by the NERC Board of Trustees	Revised
2	June 30, 2014	FERC letter order issued approving INT-009-2	

Standard INT-009-2 —Implementation of interchange

Appendix QC-INT-009-2

Provisions specific to the standard INT-009-2 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:** Implementation of Interchange
2. **Number:** INT-009-2
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: 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 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

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 INT-009-2 —Implementation of interchange

Appendix QC-INT-009-2

Provisions specific to the standard INT-009-2 applicable in Québec

Guidelines and Technical Basis

No specific provision

Version History

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New

A. Introduction

1. **Title:** Interchange Initiation and Modification for Reliability
2. **Number:** INT-010-2
3. **Purpose:** To provide guidance for required actions on Confirmed Interchange or Implemented Interchange to address reliability.
4. **Applicability:**
 - 4.1. Balancing Authority
5. **Effective Date:**

The first day of the first calendar quarter that is six months 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 six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

This standard was revised as part of the Project 2008-12 Coordinate Interchange Standards.

- R1 is modified to replace “request for Arranged Interchange” with the correct term “Request for Interchange.” A rationale was developed to clarify use of the term “energy sharing agreement” for this requirement.
- R2 and R3 are modified to shift compliance from the Reliability Coordinator to the Sink Balancing Authority.

B. Requirements and Measures

- R1.** The Balancing Authority that experiences a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement shall ensure that a Request for Interchange (RFI) is submitted with a start time no more than 60 minutes beyond the resource loss. If the use of the energy sharing agreement does not exceed 60 minutes from the time of the resource loss, no RFI is required.
[Violation Risk Factor: Lower] [Time Horizon: Real Time Operations]
- M1.** The Balancing Authority that uses its energy sharing agreement where the duration exceeds 60 minutes shall have evidence such as dated and time-stamped RFI, electronic logs or other similar evidence that it submitted an RFI per Requirement R1. (R1)
- R2.** Each Sink Balancing Authority shall ensure that a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification if a Reliability Coordinator directs the modification of a Confirmed

Interchange or Implemented Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]

- M2.** The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other similar evidence that a Reliability Adjustment Arranged Interchange was submitted within 60 minutes of the start of a modification to either a Confirmed Interchange or an Implemented Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R2)
- R3.** Each Sink Balancing Authority shall ensure that a Request for Interchange is submitted reflecting that Interchange Schedule within 60 minutes of the start of the scheduled Interchange if a Reliability Coordinator directs the scheduling of Interchange for actual or anticipated reliability-related reasons. [*Violation Risk Factor: Lower*] [*Time Horizon: Real Time Operations*]
- M3.** The Sink Balancing Authority shall have evidence such as dated and time-stamped electronic logs or other evidence that a Request for Interchange was submitted reflecting that Interchange Schedule within 60 minutes of the start of any scheduled Interchange that was directed by a Reliability Coordinator for actual or anticipated reliability-related reasons. (R3)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. 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 Balancing Authority shall maintain evidence to show compliance with R1, R2, and R3, for the most recent three calendar months plus the current month.
- If a Balancing Authority is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real Time Operations	Lower	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 60 minutes, but not more than 75 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 75 minutes, but not more than 90 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 90 minutes, but not more than 120 minutes, following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.	The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement ensured that a Request for Interchange was submitted, and it was submitted with a start time more than 120 minutes following the resource loss when the use of the energy sharing agreement exceeded 60 minutes. OR The Balancing Authority that experienced a loss of resources covered by an energy sharing agreement or other reliability needs covered by an energy sharing agreement did not ensure that a Request for Interchange was submitted following the resource loss when the use of the energy sharing agreement exceeded 60 minutes.
R2	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Reliability Adjustment

Standard INT-010-2 — Interchange Initiation and Modification for Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Arranged Interchange reflecting a modification was submitted within 60 minutes following the start of that modification.
R3	Real Time Operations	Lower	N/A	N/A	N/A	The Sink Balancing Authority did not ensure that a Request for Interchange reflecting the Interchange Schedule was submitted within 60 minutes following the start of that scheduled Interchange.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Application Guidelines

Guidelines and Technical Basis

General Considerations for Curtailments of Dynamic Transfers

The unique handling of Curtailments of Dynamic Transfers is described in NERC's Dynamic Transfer Reference Guidelines, Version 2.

For Dynamic Schedules:

If transmission service between the Source and Sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedules, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule Curtailment must also adjust the Dynamic Schedule Signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer Signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.

For Pseudo-Ties:

If transmission service between the Native and Attaining BA(s) is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.

Both sections above describe when Curtailments (typically communicated through e-Tags) of Dynamic Transfers require additional action by Balancing Authorities to ensure compliance with the Curtailment.

Curtailments of most tagged transactions are implemented through a change in the Source and Sink Balancing Authorities' ACE equations. However, changes, including Curtailments, in Dynamic Schedule and Pseudo-Tie tagged transactions do not change the Source and Sink Balancing Authorities' ACE equations directly. These types of transactions impact the ACE equation via the Dynamic Transfer Signal, not by the e-Tag. As such, Balancing Authorities need to develop additional automation or perform additional manual actions to reduce the Dynamic Transfer Signal in order to comply with the Curtailment.

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 was originally revised to replace the term "Request for an Arranged Interchange" with the defined term "Request for Interchange (RFI)" within the requirement. Additional clarification was requested regarding "energy sharing agreement." There is no NERC Glossary term for this and the CISDT believes that one is not required as these agreements are used for immediate reliability purposes. These could be regional, local, or regulatory reliability agreements which would include the applicable conditions under which the energy could be scheduled.

Application Guidelines

Version History

Version	Date	Action	Change Tracking
1	May 2, 2006	Board of Trustees Adoption	New
1	March 16, 2007	FERC Approval	New
2	February 6, 2014	Board of Trustees Adoption	Revised
2	June 30, 2014	FERC letter order issued approving INT-010-2	

Standard INT-010-2 — Interchange Initiation and Modification for reliability

Appendix QC-INT-010-2

Provisions specific to the standard INT-010-2 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:** Interchange Initiation and Modification for Reliability
2. **Number:** INT-010-2
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: 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

Table of Compliance Elements

No specific provision

D. Regional Differences

No specific provision.

E. Interpretations

No specific provision

Standard INT-010-2 — Interchange Initiation and Modification for reliability

Appendix QC-INT-010-2

Provisions specific to the standard INT-010-2 applicable in Québec

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

Revisions History

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

A. Introduction

1. **Title:** Intra-Balancing Authority Transaction Identification
2. **Number:** INT-011-1
3. **Purpose:** To ensure that transfers within a Balancing Authority Area using Point to Point Transmission Service are communicated and accounted for in congestion management procedures.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1. Load-Serving Entities

5. **Effective Date:**

The first day of the first calendar quarter that is six months 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 six months after the date this standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

6. **Background:**

This standard was created in response to a FERC directive in Order 693, paragraph 817: *In addition, e-Tagging of such transfers was previously included in INT-001-0 and the Commission is aware that such transfers are included in the e-Tagging logs. In short, the practice already exists, but if this Requirement is removed from INT-001-2, no Reliability Standard would require that such information be provided. We therefore will adopt the directive we proposed in the NOPR and direct the ERO to include a modification to INT-001-2 that includes a Requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and “non-Order No. 888” transfers.*

The transfers within a Balancing Authority Area using Point to Point Transmission Service can impact transmission congestion, and this standard ensures that these transfers are communicated and accounted for in congestion management procedures.

B. Requirements and Measures

- R1.** Each Load-Serving Entity that uses Point to Point Transmission Service for intra-Balancing Authority Area transfers shall submit a Request for Interchange unless the information about intra-Balancing Authority transfers is included in congestion management procedure(s) via an alternate method. *[Violation Risk Factor: Lower]*
[Time Horizon: Operations Planning, Same-day Operations]
- M1.** Each Load-Serving Entity subject to R1 shall have evidence, such as dated and time-stamped electronic records, documentation of congestion management procedures, or other similar evidence, that a Request for Interchange was submitted for each Point to

Point Transmission Service intra-Balancing Authority transfer subject to R1 or that each intra-Balancing Authority transfer subject to R1 was accounted for in congestion management procedure(s) via an alternate method. (R1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Load-Serving Entity shall keep data or evidence to show compliance with R1 for the most recent three months plus the current month unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	<i>Operations Planning, Same-day Operations</i>	<i>Lower</i>	N/A	N/A	N/A	The Load-Serving Entity used Point to Point Transmission Service for an intra-Balancing Authority Area transfer, and did not submit a Request for Interchange for an intra-Balancing Authority transfer that is not included in congestion management procedure(s) via an alternate method.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Application Guidelines

Version History

Version	Date	Action	Change Tracking
1	February 6, 2014	Adopted by the NERC Board of Trustees	New standard developed
1	June 30, 2014	FERC letter order issued approving INT-011-1.	

Standard INT-011-1 — Intra-Balancing Authority Transaction Identification

Appendix QC-INT-011-1

Provisions specific to the standard INT-011-1 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:** Intra-Balancing Authority Transaction Identification
2. **Number:** INT-011-1
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: 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

Table of Compliance Elements

No specific provision

D. Regional Variances

No specific provision

E. Interpretations

No specific provision

Standard INT-011-1 — Intra-Balancing Authority Transaction Identification

Appendix QC-INT-011-1

Provisions specific to the standard INT-011-1 applicable in Québec

F. Associated Documents

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New

A. Introduction

1. **Title:** Coordination of Real-time Activities Between Reliability Coordinators
2. **Number:** IRO-016-1
3. **Purpose:** To ensure that each Reliability Coordinator's operations are coordinated such that they will not have an Adverse Reliability Impact on other Reliability Coordinator Areas and to preserve the reliability benefits of interconnected operations.
4. **Applicability**
 - 4.1. Reliability Coordinator
5. **Effective Date:** November 1, 2006

B. Requirements

- R1. The Reliability Coordinator that identifies a potential, expected, or actual problem that requires the actions of one or more other Reliability Coordinators shall contact the other Reliability Coordinator(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.
 - R1.1. If the involved Reliability Coordinators agree on the problem and the actions to take to prevent or mitigate the system condition, each involved Reliability Coordinator shall implement the agreed-upon solution, and notify the involved Reliability Coordinators of the action(s) taken.
 - R1.2. If the involved Reliability Coordinators cannot agree on the problem(s) each Reliability Coordinator shall re-evaluate the causes of the disagreement (bad data, status, study results, tools, etc.).
 - R1.2.1. If time permits, this re-evaluation shall be done before taking corrective actions.
 - R1.2.2. If time does not permit, then each Reliability Coordinator shall operate as though the problem(s) exist(s) until the conflicting system status is resolved.
 - R1.3. If the involved Reliability Coordinators cannot agree on the solution, the more conservative solution shall be implemented.
- R2. The Reliability Coordinator shall document (via operator logs or other data sources) its actions taken for either the event or for the disagreement on the problem(s) or for both.
(Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1. For each event that requires Reliability Coordinator-to-Reliability Coordinator coordination, each involved Reliability Coordinator shall have evidence (operator logs or other data sources) of the actions taken for either the event or for the disagreement on the problem or for both.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**
Regional Reliability Organization
 - 1.2. **Compliance Monitoring Period and Reset Time Frame**
The performance reset period shall be one calendar year.

1.3. Data Retention

The Reliability Coordinator shall keep auditable evidence for a rolling 12 months. In addition, entities found non-compliant shall keep information related to the non-compliance until it has been found compliant. The Compliance Monitor shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer.

1.4. Additional Compliance Information

The Reliability Coordinator shall demonstrate compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor shall use a scheduled on-site review at least once every three years. The Compliance Monitor shall conduct an investigation upon a complaint that is received within 30 days of an alleged infraction’s discovery date. The Compliance Monitor shall complete the investigation and report back to all involved Reliability Coordinators (the Reliability Coordinator that complained as well as the Reliability Coordinator that was investigated) within 45 days after the start of the investigation. As part of an audit or investigation, the Compliance Monitor shall interview other Reliability Coordinators within the Interconnection and verify that the Reliability Coordinator being audited or investigated has been coordinating actions to prevent or resolve potential, expected, or actual problems that adversely impact the Interconnection.

The Reliability Coordinator shall have the following available for its Compliance Monitor to inspect during a scheduled, on-site review or within five working days of a request as part of an investigation upon complaint:

- 1.4.1 Evidence (operator log or other data source) to show coordination with other Reliability Coordinators.

2. Levels of Non-Compliance

- 2.1. **Level 1:** For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did coordinate, but did not have evidence that it coordinated with other Reliability Coordinators.
- 2.2. **Level 2:** Not applicable.
- 2.3. **Level 3:** Not applicable.
- 2.4. **Level 4:** For potential, actual or expected events which required Reliability Coordinator-to-Reliability Coordinator coordination, the Reliability Coordinator did not coordinate with other Reliability Coordinators.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	August 10, 2005	1. Changed incorrect use of certain hyphens (-) to “en dash (–).” 2. Hyphenated “30-day” and “Reliability Coordinator-to-Reliability Coordinator” when used as adjective.	01/20/06

Standard IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators

Appendix QC-IRO-016-1 Provisions specific to the standard IRO-016-1 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:** Coordination of Real-time Activities Between Reliability Coordinators
2. **Number:** IRO-016-1
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: Month x, 201x

B. Requirements

No specific provision

C. Measures

No specific provision

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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. Compliance Monitoring Period and Reset Time Frame

No specific provision

1.3. Data Retention

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Levels of Non-Compliance

No specific provision

E. Regional Differences

No specific provision

Standard IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators

**Appendix QC-IRO-016-1
Provisions specific to the standard IRO-016-1 applicable in Québec**

Revision History

Revision	Adoption Date	Action	Change Tracking
0	October 30, 2013	New appendix	New
1	Month xx, 201x	<ul style="list-style-type: none">• Modification of adoption dates	

Standard IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators

		<ol style="list-style-type: none"> 3. Changed standard header to be consistent with standard “Title.” 4. Added “periods” to items where appropriate. 5. Initial capped heading “Definitions of Terms Used in Standard.” 6. Changed “Timeframe” to “Time Frame” in item D, 1.2. 7. Lower cased all words that are not “defined” terms — drafting team, and self-certification. 8. Changed apostrophes to “smart” symbols. 9. Removed comma after word “condition” in item R.1.1. 10. Added comma after word “expected” in item 1.4, last sentence. 11. Removed extra spaces between words where appropriate. 	
1	February 7, 2006	Adopted by NERC Board of Trustees	
1	March 16, 2007	Approved by FERC	
1	February 7, 2013	R2 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.	
1	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

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

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

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.

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

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:

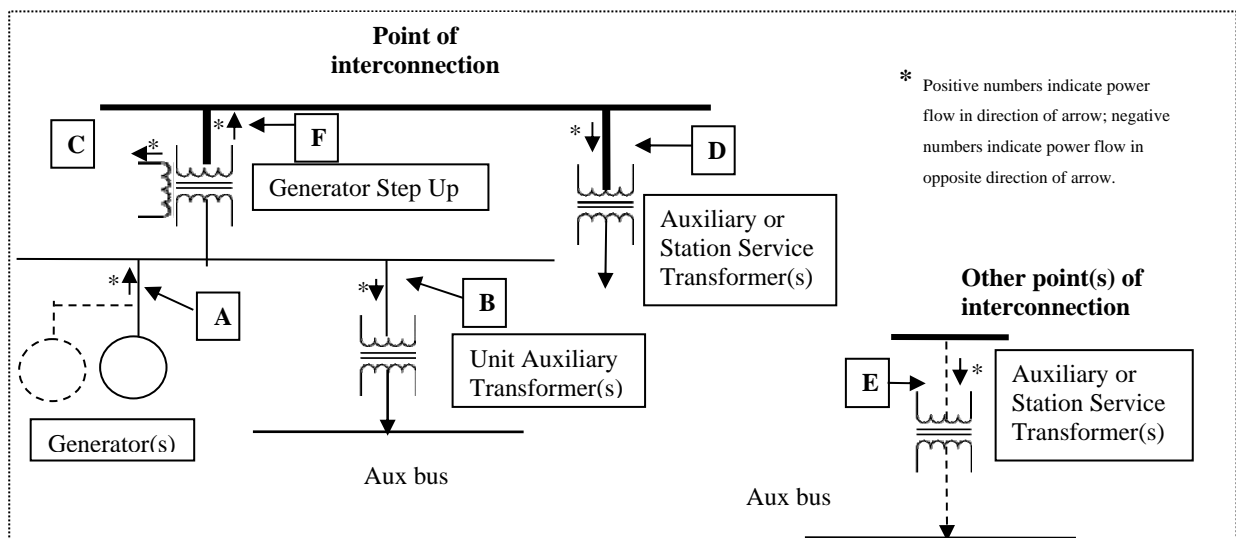
Unit No.:

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

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.

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

- 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>

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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

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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	<p>Existing applicable unit that is equivalent to another 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 ≤ 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>
5	<p>The Generator Owner has submitted a verification plan.</p> <p>(Requirement R3, R4 or R5)</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-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 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

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**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).

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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

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

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>

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

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
<p>NOTES:</p> <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: Area Interchange Methodology**
2. **Number: MOD-028-2**
3. **Purpose:** To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.
4. **Applicability:**
 - 4.1. Each Transmission Operator that uses the Area Interchange Methodology to calculate Total Transfer Capabilities (TTCs) for ATC Paths.
 - 4.2. Each Transmission Service Provider that uses the Area Interchange Methodology to calculate Available Transfer Capabilities (ATCs) for ATC Paths.
5. **Proposed Effective Date:** In those jurisdictions where regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, this standard shall become effective on the first day of the first calendar quarter after Board of Trustees approval.

B. Requirements

- R1. Each Transmission Service Provider shall include in its Available Transfer Capability Implementation Document (ATCID), at a minimum, the following information relative to its methodology for determining Total Transfer Capability (TTC): [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]
 - R1.1. Information describing how the selected methodology has been implemented, in such detail that, given the same information used by the Transmission Operator, the results of the TTC calculations can be validated.
 - R1.2. A description of the manner in which the Transmission Operator will account for Interchange Schedules in the calculation of TTC.
 - R1.3. Any contractual obligations for allocation of TTC.
 - R1.4. A description of the manner in which Contingencies are identified for use in the TTC process.
 - R1.5. The following information on how source and sink for transmission service is accounted for in ATC calculations including:
 - R1.5.1. Define if the source used for Available Transfer Capability (ATC) calculations is obtained from the source field or the Point of Receipt (POR) field of the transmission reservation
 - R1.5.2. Define if the sink used for ATC calculations is obtained from the sink field or the Point of Delivery (POD) field of the transmission reservation

- R4.3.** Include, for each time period, the Firm Transmission Service expected to be scheduled as specified in the ATCID (filtered to reduce or eliminate duplicate impacts from transactions using Transmission service from multiple Transmission Service Providers) for the Transmission Service Provider, all adjacent Transmission Service Providers, and any Transmission Service Providers with which coordination agreements have been executed modeling the source and sink as follows:
- If the source, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point as the source.
 - If the source, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the source.
 - If the source, as specified in the ATCID, has been identified in the reservation and the point cannot be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
 - If the source, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider from which the power is to be received as the source.
 - If the sink, as specified in the ATCID, has been identified in the reservation and it is discretely modeled in the Transmission Service Provider’s Transmission model, use the discretely modeled point shall as the sink.
 - If the sink, as specified in the ATCID, has been identified in the reservation and the point can be mapped to an “equivalence” or “aggregate representation” in the Transmission Service Provider’s Transmission model, use the modeled equivalence or aggregate as the sink.
 - If the sink, as specified in the ATCID, has been identified in the reservation and the point can not be mapped to a discretely modeled point, an “equivalence,” or an “aggregate representation” in the Transmission Service Provider’s Transmission model, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is to be delivered as the sink.
 - If the sink, as specified in the ATCID, has not been identified in the reservation, use the immediately adjacent Balancing Authority associated with the Transmission Service Provider to which the power is being delivered as the sink.

- R5.** Each Transmission Operator shall establish TTC for each ATC Path as defined below:
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R5.1.** At least once within the seven calendar days prior to the specified period for TTCs used in hourly and daily ATC calculations.
 - R5.2.** At least once per calendar month for TTCs used in monthly ATC calculations.
 - R5.3.** Within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a transformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage, provided such outage is expected to last 24 hours or longer.
- R6.** Each Transmission Operator shall establish TTC for each ATC Path using the following process: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- R6.1.** Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either:
 - A System Operating Limit is reached on the Transmission Service Provider’s system, or
 - A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater¹.
 - R6.2.** If the limit in step R6.1 can not be reached by adjusting any combination of load or generation, then set the incremental Transfer Capability by the results of the case where the maximum adjustments were applied.
 - R6.3.** Use (as the TTC) the lesser of:
 - The sum of the incremental Transfer Capability and the impacts of Firm Transmission Services, as specified in the Transmission Service Provider’s ATCID, that were included in the study model, or
 - The sum of Facility Ratings of all ties comprising the ATC Path.
 - R6.4.** For ATC Paths whose capacity uses jointly-owned or allocated Facilities, limit TTC for each Transmission Service Provider so the TTC does not exceed each Transmission Service Provider’s contractual rights.
- R7.** The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R7.1.** One calendar day after its determination for TTCs used in hourly and daily ATC calculations.
 - R7.2.** Seven calendar days after its determination for TTCs used in monthly ATC calculations.

¹ The Transmission operator may honor distribution factors less than 5% if desired.

- R8.** When calculating Existing Transmission Commitments (ETCs) for firm commitments (ETC_F) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_F = NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

- $NITS_F$** is the firm capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) on ATC Paths that serve as interfaces with other Balancing Authorities.
- GF_F** is the firm capacity set aside for Grandfathered Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.
- PTP_F** is the firm capacity reserved for confirmed Point-to-Point Transmission Service.
- ROR_F** is the capacity reserved for roll-over rights for Firm Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.
- OS_F** is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.
- R9.** When calculating ETC for non-firm commitments (ETC_{NF}) for all time periods for an ATC Path the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

- $NITS_{NF}$** is the non-firm capacity set aside for Network Integration Transmission Service (i.e., secondary service, including the capacity used to serve bundled load within the Transmission Service Provider's area with external sources) reserved on ATC Paths that serve as interfaces with other Balancing Authorities.
- GF_{NF}** is the non-firm capacity reserved for Grandfathered Non-Firm Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or safe harbor tariff on ATC Paths that serve as interfaces with other Balancing Authorities.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Non-Firm Transmission Service, including any other firm adjustments to reflect impacts from other ATC Paths of the Transmission Service Provider as specified in the ATCID.

- R10.** When calculating firm ATC for an ATC Path for a specified period, the Transmission Service Provider shall utilize the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_F = TTC - ETC_F - CBM - TRM + Postbacks_F + counterflows_F$$

Where:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

Postbacks_F are changes to firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_F are adjustments to firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

- R11.** When calculating non-firm ATC for a ATC Path for a specified period, the Transmission Service Provider shall use the following algorithm: [*Violation Risk Factor: Lower*] [*Time Horizon: Operations Planning*]

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{SNF} + counterflows_{SNF}$$

Where:

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

ETC_F is the sum of existing firm Transmission commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm Transmission commitments for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

Postbacks_{NF} are changes to non-firm ATC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

counterflows_{NF} are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified in the ATCID.

C. Measures

- M1.** Each Transmission Service Provider shall provide its current ATCID that has the information described in R1 to show compliance with R1. (R1)
- M2.** Each Transmission Operator shall provide evidence including the model used to calculate TTC as well as other evidence (such as Facility Ratings provided by facility owners, written documentation, logs, and data) to show that the modeling requirements in R2 were met. (R2)
- M3.** Each Transmission Operator shall provide evidence, including scheduled outages, facility additions and retirements, (such as written documentation, logs, and data) that the data described in R3 and R4 were included in the determination of TTC as specified in the ATCID. (R3)
- M4.** Each Transmission Operator shall provide the contingencies used in determining TTC and the ATCID as evidence to show that the contingencies described in the ATCID were included in the determination of TTC. (R4)
- M5.** Each Transmission Operator shall provide copies of contracts that contain requirements to allocate TTCs and TTC values to show that any contractual allocations of TTC were respected as required in R4.2. (R4)
- M6.** Each Transmission Operator shall provide evidence (such as copies of coordination agreements, reservations, interchange transactions, or other documentation) to show that firm reservations were used to estimate scheduled interchange, the modeling of scheduled interchange was based on the rules described in R4.3, and that estimated scheduled interchange was included in the determination of TTC. (R4)
- M7.** Each Transmission Operator shall provide evidence (such as logs and data and dated copies of requests from the Transmission Service Provider to establish TTCs at specific intervals) that TTCs have been established at least once in the calendar week prior to the specified period for TTCs used in hourly and daily ATC calculations, at least once per calendar month for TTCs used in monthly ATC calculations, and within 24 hours of the unexpected outage of a 500 kV or higher transmission Facility or a autotransformer with a low-side voltage of 200 kV or higher for TTCs in effect during the anticipated duration of the outage; provided such outage is expected to last 24 hours or longer in duration per the specifications in R5.(R5)
- M8.** Each Transmission Operator shall provide evidence (such as written documentation) that TTCs have been calculated using the process described in R6. (R6)
- M9.** Each Transmission Operator shall have evidence including a copy of the latest calculated TTC values along with a dated copy of email notices or other equivalent evidence to show that it provided its Transmission Service Provider with the most current values for TTC in accordance with R7. (R7)

- M10.** The Transmission Service Provider shall demonstrate compliance with R8 by recalculating firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R8 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its firm ETC. (R8)
- M11.** The Transmission Service Provider shall demonstrate compliance with R9 by recalculating non-firm ETC for any specific time period as described in (MOD-001 R2), using the algorithm defined in R9 and with data used to calculate the specified value for the designated time period. The data used must meet the requirements specified in MOD-028-2 and the ATCID. To account for differences that may occur when recalculating the value (due to mixing automated and manual processes), any recalculated value that is within +/- 15% or 15 MW, whichever is greater, of the originally calculated value, is evidence that the Transmission Service Provider used the algorithm in R8 to calculate its non-firm ETC. (R9)
- M12.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates firm ATCs, as required in R10. Such documentation must show that only the variables allowed in R10 were used to calculate firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R10)
- M13.** Each Transmission Service Provider shall produce the supporting documentation for the processes used to implement the algorithm that calculates non-firm ATCs, as required in R11. Such documentation must show that only the variables allowed in R11 were used to calculate non-firm ATCs, and that the processes use the current values for the variables as determined in the requirements or definitions. Note that any variable may legitimately be zero if the value is not applicable or calculated to be zero (such as counterflows, TRM, CBM, etc...). The supporting documentation may be provided in the same form and format as stored by the Transmission Service Provider. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

For functional entities that work for their Regional Entity, the ERO or a Regional Entity approved by the ERO and FERC or other applicable governmental authorities shall serve as the Compliance Enforcement Authority.

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 Transmission Operator and Transmission Service Provider shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Service Provider shall retain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit to show compliance with R1.
- The Transmission Operator shall have its latest model used to calculate TTC and evidence of the previous version to show compliance with R2.
- The Transmission Operator shall retain evidence to show compliance with R3 for the most recent 12 months or until the model used to calculate TTC is updated, whichever is longer.
- The Transmission Operator shall retain evidence to show compliance with R4, R5, R6 and R7 for the most recent 12 months.
- The Transmission Service Provider shall retain evidence to show compliance in calculating hourly values required in R8 and R9 for the most recent 14 days; evidence to show compliance in calculating daily values required in R8 and R9 for the most recent 30 days; and evidence to show compliance in calculating monthly values required in R8 and R9 for the most recent 60 days.
- The Transmission Service Provider shall retain evidence to show compliance with R10 and R11 for the most recent 12 months.
- If a Transmission Service Provider or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	<p>The Transmission Service Provider has an ATCID but it is missing one of the following:</p> <ul style="list-style-type: none"> ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements) 	<p>The Transmission Service Provider has an ATCID but it is missing two of the following:</p> <ul style="list-style-type: none"> ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements) 	<p>The Transmission Service Provider has an ATCID but it is missing three of the following:</p> <ul style="list-style-type: none"> ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements) 	<p>The Transmission Service Provider has an ATCID but it is missing more than three of the following:</p> <ul style="list-style-type: none"> ▪ R1.1 ▪ R1.2 ▪ R1.3 ▪ R1.4 ▪ R1.5 (any one or more of its sub-subrequirements)
R2.	<p>The Transmission Operator used one to ten Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</p>	<p>The Transmission Operator used eleven to twenty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model.</p>	<p>One or both of the following:</p> <ul style="list-style-type: none"> • The Transmission Operator used twenty-one to thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for one adjacent Reliability Coordinator Area. 	<p>One or more of the following:</p> <ul style="list-style-type: none"> • The Transmission Operator used more than thirty Facility Ratings that were different from those specified by a Transmission or Generator Owner in their Transmission model. • The Transmission Operator's model includes equivalent representation of non-radial facilities greater than 161 kV for its own Reliability Coordinator Area. • The Transmission Operator did not use a Transmission model that includes modeling data and topology (or equivalent representation) for two or more adjacent Reliability Coordinator

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Areas.
R3.	The Transmission Operator did not include in the TTC process one to ten expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process eleven to twenty-five expected generation and Transmission outages, additions or retirements as specified in the ATCID.	The Transmission Operator did not include in the TTC process twenty-six to fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID.	One or more of the following: <ul style="list-style-type: none"> • The Transmission Operator did not include in the TTC process more than fifty expected generation and Transmission outages, additions or retirements as specified in the ATCID. • The Transmission Operator did not include the Load forecast or unit commitment in its TTC calculation as described in R3.
R4.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than zero reservations, but not more than 5% of all reservations; or 1 reservation, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 5%, but not more than 10% of all reservations; or 2 reservations, whichever is greater.	The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 10%, but not more than 15% of all reservations; or 3 reservations, whichever is greater.	One or more of the following: <ul style="list-style-type: none"> • The Transmission Operator did not include in the TTC calculation the contingencies that met the criteria described in the ATCID. • The Transmission Operator did not respect contractual allocations of TTC. • The Transmission Operator did not model reservations' sources or sinks as described in R4.3 for more than 15% of all reservations; or more than 3 reservations, whichever is greater. • The Transmission Operator did not use firm reservations to estimate interchange or did not

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
				utilize that estimate in the TTC calculation as described in R4.3.
R5.	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not establish TTCs for use in hourly or daily ATCs within 7 calendar days but did establish the values within 10 calendar days The Transmission Operator did not establish TTCs for use in monthly ATCs during a calendar month but did establish the values within the next consecutive calendar month 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not establish TTCs for use in hourly or daily ATCs in 10 calendar days but did establish the values within 13 calendar days The Transmission Operator did not establish TTCs for use in monthly ATCs during a two consecutive calendar month period but did establish the values within the third consecutive calendar month 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 13 calendar days but did establish the values within 16 calendar days The Transmission Operator did not establish TTCs for use in monthly ATCs during a three consecutive calendar month period but did establish the values within the fourth consecutive calendar month 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator did not establish TTCs for used in hourly or daily ATCs in 16 calendar days The Transmission Operator did not establish TTCs for use in monthly ATCs during a four or more consecutive calendar month period The Transmission Operator did not establish TTCs within 24 hrs of the triggers defined in R5.3
R6.	N/A	N/A	N/A	The Transmission Operator did not calculate TTCs per the process specified in R6.
R7.	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than one calendar day after their determination, but not been more than two calendar days after their determination. The Transmission Operator 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than two calendar days after their determination, but not been more than three calendar days after their determination. The Transmission Operator 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than three calendar days after their determination, but not been more than four calendar days after their determination. The Transmission Operator 	<p>One or more of the following:</p> <ul style="list-style-type: none"> The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in hourly or daily ATC calculations more than four calendar days after their determination. The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in hourly or

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	<p>has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than seven calendar days after their determination, but not more than 14 calendar days since their determination.</p>	<p>has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 14 calendar days after their determination, but not been more than 21 calendar days after their determination.</p>	<p>has not provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 21 calendar days after their determination, but not been more than 28 calendar days after their determination.</p>	<p>daily ATC calculations.</p> <ul style="list-style-type: none"> • The Transmission Operator provided its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations more than 28 calendar days after their determination. • The Transmission Operator did not provide its Transmission Service Provider with its ATC Path TTCs used in monthly ATC calculations.
R8.	<p>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not more than 25% of the value calculated in the measure or 25MW, whichever is greater.</p>	<p>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not more than 35% of the value calculated in the measure or 35MW, whichever is greater.</p>	<p>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not more than 45% of the value calculated in the measure or 45MW, whichever is greater.</p>	<p>For a specified period, the Transmission Service Provider calculated a firm ETC with an absolute value different than that calculated in M10 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.</p>
R9.	<p>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 15% of the value calculated in the measure or 15MW, whichever is greater, but not</p>	<p>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 25% of the value calculated in the measure or 25MW, whichever is greater, but not</p>	<p>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 35% of the value calculated in the measure or 35MW, whichever is greater, but not</p>	<p>For a specified period, the Transmission Service Provider calculated a non-firm ETC with an absolute value different than that calculated in M11 for the same period, and the absolute value difference was more than 45% of the value calculated in the measure or 45MW, whichever is greater.</p>

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R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 25% of the value calculated in the measure or 25MW, whichever is greater.	more than 35% of the value calculated in the measure or 35MW, whichever is greater.	more than 45% of the value calculated in the measure or 45MW, whichever is greater.	
R10.	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R10 when determining firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).
R11.	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than zero ATC Paths, but not more than 5% of all ATC Paths or 1 ATC Path (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 5% of all ATC Paths or 1 ATC Path (whichever is greater), but not more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 10% of all ATC Paths or 2 ATC Paths (whichever is greater), but not more than 15% of all ATC Paths or 3 ATC Paths (whichever is greater).	The Transmission Service Provider did not use all the elements defined in R11 when determining non-firm ATC, or used additional elements, for more than 15% of all ATC Paths or more than 3 ATC Paths (whichever is greater).

Version History

Version	Date	Action	Change Tracking
1	August 26, 2008	Adopted by the Board of Trustees	
1	July 24, 2013	Updated VSLs based on June 24, 2013 approval.	
2	February 9, 2012	Adopted by the Board of Trustees	
2	July 24, 2013	FERC order issued July 18, 2013 approving MOD-028-2	

Standard MOD-028-2 — Area Interchange Methodology

Appendix QC-MOD-028-2

Provisions specific to the standard MOD-028-2 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:** Area Interchange Methodology
2. **Number:** MOD-028-2
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: 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. Data Retention

No specific provision

1.3. Compliance Monitoring and Enforcement Processes

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

Revision History

Version	Date	Action	Change Tracking
0	Month 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.

<p align="center">steady-state</p> <p 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 align="center">dynamics</p> <p 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 align="center">short circuit</p>
<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**
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

MOD-032-1 — Data for Power System Modeling and Analysis

Appendix QC-MOD-032-1

Provisions specific to the standard MOD-032-1 applicable in Québec

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.	

MOD-033-1 — Steady-State and Dynamic System Model Validation

Appendix QC-MOD-033-1

Provisions specific to the standard MOD-033-1 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:** 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**
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

MOD-033-1 — Steady-State and Dynamic System Model Validation

Appendix QC-MOD-033-1

Provisions specific to the standard MOD-033-1 applicable in Québec

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:** Operations Personnel Training
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.
4. **Applicability:**
 - 4.1. **Functional Entities:**
 - 4.1.1 Reliability Coordinator
 - 4.1.2 Balancing Authority
 - 4.1.3 Transmission Operator
 - 4.1.4 Transmission Owner that has:
 - 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.
 - 4.1.5 Generator Operator that has:
 - 4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.
5. **Effective Date:**
 - 5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard 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.

B. Requirements and Measures

- R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.
 - 1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.
 - 1.2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.
 - 1.3.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.
 - 1.4.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
- M1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.
- M1.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.
 - M1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.
 - M1.3** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

- M1.4** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.
- R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 2.1.** Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.
- 2.1.1.** Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.
- 2.2.** Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.
- 2.3.** Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.
- 2.4.** Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.
- M2.** Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.
- M2.1** Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.
- M2.2** Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.
- M2.3** Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.
- M2.4** Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

- R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.
- M3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.
- M3.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.
- R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- 4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.
- M4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed

training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

- M6.1** Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator, Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	<p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)</p>	<p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)</p>	<p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)</p>
R2	Long-term Planning	Medium	None	<p>The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-</p>	<p>The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)</p>	<p>The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.)</p> <p>OR</p>

PER-005-2 — Operations Personnel Training

				<p>related task list each calendar year. (2.1.1.)</p> <p>OR</p> <p>The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4)</p> <p>OR</p> <p>The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)</p>	<p>OR</p> <p>The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)</p>	<p>The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)</p>
R3	Long-term Planning	High	None	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)</p>	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement</p>	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)</p>

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					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	Long-term Planning	Medium	None	None	None	<p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4)</p> <p>OR</p> <p>The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)</p>

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R5	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	Long-term Planning	Medium	None	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Application Guidelines

Reference #2: Systematic Approach to Training References:

The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

- (1) DOE-HDBK-1078-94, A Systematic Approach to Training

<http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf>

- (2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

- (3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

- (4) DOE Standard - Table-Top Needs Analysis

DOE-HDBK-1103-96

<http://energy.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf>

Reference #3: Recognized Operator Training Topics

See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.

http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering

http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training

Just what is "simulation" anyway (or, Simulation 101)?

And what about "modeling"?

But what does IST do with simulations?

<http://www.ist.ucf.edu/overview.htm>

Application Guidelines

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 System Operator:

The definition of the existing NERC Glossary Term “System Operator” has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term “System Operator” contains another NERC Glossary term “Control Center”, which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of “System Operator” do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

Rationale for Operations Support Personnel:

The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Rationale for TO:

Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *“exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap.”* See FERC Order 693 at P 1343 and 1347.

Rationale for GOP:

Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that *“although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions,*

Application Guidelines

particularly in an emergency situation in which instructions may be succinct and require immediate action.” Order No. 742 further clarified that the directive “*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2.*” Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

Rationale for changes to R2:

Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

Rationale for R3:

This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

Rationale for changes to R4:

The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

Rationale for R5:

This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

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Rationale for R6:

This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

Version History

Version	Date	Action	Change Tracking
1	2/10/2009	Adopted by the NERC Board of Trustees	
1	11/18/2010	FERC Approved	
1	8/26/2013	Updated VSLs based on June 24, 2013 approval.	
2	2/6/2014	Adopted by the NERC Board of Trustees	
2	6/19/2014	FERC Approved	

Standard PER-005-2 —Operations Personnel Training

Appendix QC-PER-005-2

Provisions specific to the standard PER-005-2 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:** Operations Personnel Training
2. **Number:** PER-005-2
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: 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

Standard PER-005-2 —Operations Personnel Training

Appendix QC-PER-005-2

Provisions specific to the standard PER-005-2 applicable in Québec

E. Interpretations

No specific provision

F. Associated Documents

No specific provision

Guidelines and Technical Basis

No specific provision

Revision History

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

A. Introduction

- 1. Title:** Protection System Maintenance
- 2. Number:** PRC-005-2
- 3. Purpose:** To document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.
- 4. Applicability:**
 - 4.1. Functional Entities:**
 - 4.1.1** Transmission Owner
 - 4.1.2** Generator Owner
 - 4.1.3** Distribution Provider
 - 4.2. Facilities:**
 - 4.2.1** Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)
 - 4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.
 - 4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.
 - 4.2.4** Protection Systems installed as a Special Protection System (SPS) for BES reliability.
 - 4.2.5** Protection Systems for generator Facilities that are part of the BES, including:
 - 4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.
 - 4.2.5.2** Protection Systems for generator step-up transformers for generators that are part of the BES.
 - 4.2.5.3** Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
 - 4.2.5.4** Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
- 5. Effective Date:** See Implementation Plan

B. Requirements

- R1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

The PSMP shall:

- 1.1.** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System Component Type. All batteries associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.
- 1.2.** Include the applicable monitored Component attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Component Type - Any one of the five specific elements of the Protection System definition.

Component – A component is any individual discrete piece of equipment included in a Protection System, including but not limited to a protective relay or current sensing device. The designation of what constitutes a control circuit component is very dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed the latitude to designate their own definitions of control circuit components. Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.

Unresolved Maintenance Issue - A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

C. Measures

- M1.** Each Transmission Owner, Generator Owner and Distribution Provider shall have a documented Protection System Maintenance Program in accordance with Requirement R1.

For each Protection System Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each protection Component Type (such as manufacturer’s specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, and Table 3. (Part 1.2)
- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include but is not limited to Component lists, dated maintenance records, and dated analysis records and results.
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System Components included within its time-based program in accordance with Requirement R3. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the Protection System Maintenance Program for the Protection System Components included in its performance-based program in accordance with Requirement R4. The evidence may include but is not limited to dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.
- M5.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include but is not limited to work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

D. Compliance

- 1. Compliance Monitoring Process**

 - 1.1. Compliance Enforcement Authority**

 - Regional Entity
 - 1.2. Compliance Monitoring and Enforcement Processes:**

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

1.3. Evidence Retention

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

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

For Requirement R1, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep its current dated Protection System Maintenance Program, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System Component Type.

For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System Component, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity’s PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The responsible entity’s PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1)	The responsible entity’s PSMP failed to include the applicable monitoring attributes applied to each Protection System Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System Components. (Part 1.2).	The responsible entity failed to establish a PSMP. OR The responsible entity failed to specify whether three or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1). OR The responsible entity’s PSMP failed to include applicable station batteries in a time-based program. (Part 1.1)
R2	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years.	NA	The responsible entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years.	The responsible entity uses performance-based maintenance intervals in its PSMP but: 1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP OR 2) Failed to reduce Countable Events to no more than 4% within five years OR 3) Maintained a Segment with less than 60 Components OR 4) Failed to:

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				<ul style="list-style-type: none"> • Annually update the list of Components, OR • Annually perform maintenance on the greater of 5% of the segment population or 3 Components, OR • Annually analyze the program activities and results for each Segment.
R3	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain 5% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.	For Protection System Components included within a time-based maintenance program, the responsible entity failed to maintain more than 15% of the total Components included within a specific Protection System Component Type, in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.
R4	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.	For Protection System Components included within a performance-based maintenance program, the responsible entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Protection System Component Type in accordance with their performance-based PSMP.

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Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	The responsible entity failed to undertake efforts to correct 5 or fewer identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 5, but less than or equal to 10 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 10, but less than or equal to 15 identified Unresolved Maintenance Issues.	The responsible entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues.

E. Regional Variances

None

F. Supplemental Reference Document

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference and FAQ — July 2012.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	December 1, 2005	<ol style="list-style-type: none"> 1. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 2. Added “periods” to items where appropriate. 3. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	01/20/05
1a	February 17, 2011	Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers	Project 2009-17 interpretation
1a	February 17, 2011	Adopted by Board of Trustees	
1a	September 26, 2011	FERC Order issued approving interpretation of R1 and R2 (FERC’s Order is effective as of September 26, 2011)	
1.1a	February 1, 2012	Errata change: Clarified inclusion of generator interconnection Facility in Generator Owner’s responsibility	Revision under Project 2010-07
1b	February 3, 2012	FERC Order issued approving interpretation of R1, R1.1, and R1.2 (FERC’s Order dated March 14, 2012). Updated version from 1a to 1b.	Project 2009-10 Interpretation
1.1b	April 23, 2012	Updated standard version to 1.1b to reflect FERC approval of PRC-005-1b.	Revision under Project 2010-07

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1.1b	May 9, 2012	PRC-005-1.1b was adopted by the Board of Trustees as part of Project 2010-07 (GOTO).	
2	November 7, 2012	Adopted by Board of Trustees	Complete revision, absorbing maintenance requirements from PRC-005-1b, PRC-008-0, PRC-011-0, PRC-017-0
2	October 17, 2013	Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase “or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;” to the second sentence under the “Retirement of Existing Standards” section.	
2	December 19, 2013	FERC Order issued approving PRC-005-2. (The enforcement date for PRC-005-2 will be April 1, 2015, which is the first date entities must be compliant with part of the standard. The implementation plan for PRC-005-2 includes specific compliance dates and timeframes for each of the Requirements. The regulatory approval date in the U.S. is February 24, 2014.	
2	May 7, 2014	Adopted by the NERC Board of Trustees to modify VSLs for Requirement R1.	
2	August 25, 2014	FERC issued letter order to modify VSLs for Requirement R1.	

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ¹	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	For all unmonitored relays: <ul style="list-style-type: none"> • Verify that settings are as specified For non-microprocessor relays: <ul style="list-style-type: none"> • Test and, if necessary calibrate For microprocessor relays: <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
Monitored microprocessor protective relay with the following: <ul style="list-style-type: none"> • Internal self-diagnosis and alarming (see Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. • Alarming for power supply failure (see Table 2). 	12 calendar years	Verify: <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values.

¹ For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed. For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

Table 1-1 Component Type - Protective Relay Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval ¹	Maintenance Activities
Monitored microprocessor protective relay with preceding row attributes and the following: <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). • Alarming for change of settings (See Table 2). 	12 calendar years	Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.

Table 1-2 Component Type - Communications Systems Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.	4 calendar months	Verify that the communications system is functional.
	6 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2).	12 calendar years	Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate). Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System.
Any communications system with all of the following: <ul style="list-style-type: none"> • Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation). (See Table 2) • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). 	12 calendar years	Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System

Table 1-3 Component Type - Voltage and Current Sensing Devices Providing Inputs to Protective Relays Excluding distributed UFLS and distributed UVLS (see Table 3)		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any voltage and current sensing devices not having monitoring attributes of the category below.	12 calendar years	Verify that current and voltage signal values are provided to the protective relays.
Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2).	No periodic maintenance specified	None.

Table 1-4(a)
Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Excluding distributed UFLS and distributed UVLS (see Table 3)

Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible • Physical condition of battery rack
	18 Calendar Months -or- 6 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(b) Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	6 Calendar Months	Inspect: <ul style="list-style-type: none"> • Condition of all individual units by measuring battery cell/unit internal ohmic values.
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Physical condition of battery rack
	6 Calendar Months -or- 3 Calendar Years	Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline. -or- Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(c) Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: <ul style="list-style-type: none"> • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: <ul style="list-style-type: none"> • Cell condition of all individual battery cells. • Physical condition of battery rack
	6 Calendar Years	Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.

Table 1-4(d) Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage Excluding distributed UFLS and distributed UVLS (see Table 3)		
Protection System Station dc supply used only for non-BES interrupting devices for SPS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)).		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).	4 Calendar Months	Verify: <ul style="list-style-type: none"> • Station dc supply voltage Inspect: <ul style="list-style-type: none"> • For unintentional grounds
	18 Calendar Months	Inspect: Condition of non-battery based dc supply
	6 Calendar Years	Verify that the dc supply can perform as manufactured when ac power is not present.

Table 1-4(e)

Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for SPS, non-distributed UFLS, and non-distributed UVLS systems

Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a SPS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f).	When control circuits are verified (See Table 1-5)	Verify Station dc supply voltage.

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Table 1-4(f) Exclusions for Protection System Station dc Supply Monitoring Devices and Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2).	No periodic maintenance specified	No periodic verification of station dc supply voltage is required.
Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2).		No periodic inspection of the electrolyte level for each cell is required.
Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2).		No periodic inspection of unintentional dc grounds is required.
Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2).		No periodic verification of float voltage of battery charger is required.
Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2).		No periodic verification of the battery continuity is required.
Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery (See Table 2).		No periodic verification of the intercell and terminal connection resistance is required.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and evaluating present values relative to baseline internal ohmic values for every cell/unit (See Table 2).		No periodic evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured.
Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with monitoring and alarming of each cell/unit internal ohmic value (See Table 2).		No periodic inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery is required.

Table 1-5 Component Type - Control Circuitry Associated With Protective Functions Excluding distributed UFLS and distributed UVLS (see Table 3) Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and SPSs except as noted.		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry).	6 calendar years	Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.
Electromechanical lockout devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 calendar years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with SPS.	12 calendar years	Verify all paths of the control circuits essential for proper operation of the SPS.
Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays.	12 calendar years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with protective functions and/or SPS whose integrity is monitored and alarmed (See Table 2).	No periodic maintenance specified	None.

Table 2 – Alarming Paths and Monitoring In Tables 1-1 through 1-5 and Table 3, alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any alarm path through which alarms in Tables 1-1 through 1-5 and Table 3 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the “Alarm Path with monitoring” category below. Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.	12 Calendar Years	Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated.
Alarm Path with monitoring: The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated.	No periodic maintenance specified	None.

Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Any unmonitored protective relay not having all the monitoring attributes of a category below.	6 calendar years	<p>Verify that settings are as specified</p> <p>For non-microprocessor relays:</p> <ul style="list-style-type: none"> • Test and, if necessary calibrate <p>For microprocessor relays:</p> <ul style="list-style-type: none"> • Verify operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Verify acceptable measurement of power system input values.
<p>Monitored microprocessor protective relay with the following:</p> <ul style="list-style-type: none"> • Internal self diagnosis and alarming (See Table 2). • Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. <p>Alarming for power supply failure (See Table 2).</p>	12 calendar years	<p>Verify:</p> <ul style="list-style-type: none"> • Settings are as specified. • Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System. • Acceptable measurement of power system input values
<p>Monitored microprocessor protective relay with preceding row attributes and the following:</p> <ul style="list-style-type: none"> • Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). • Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). <p>Alarming for change of settings (See Table 2).</p>	12 calendar years	<p>Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Protection System.</p>

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Table 3 Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems		
Component Attributes	Maximum Maintenance Interval	Maintenance Activities
Voltage and/or current sensing devices associated with UFLS or UVLS systems.	12 calendar years	Verify that current and/or voltage signal values are provided to the protective relays.
Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system.	12 calendar years	Verify Protection System dc supply voltage.
Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils).	12 calendar years	Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic).
Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils).	12 calendar years	Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices.
Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS relays (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils).	No periodic maintenance specified	None.
Trip coils of non-BES interrupting devices in UFLS or UVLS systems.	No periodic maintenance specified	None.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of Components included in each designated Segment of the Protection System Component population, with a minimum **Segment** population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5 and Table 3 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences **Countable Events** on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

Segment – *Protection Systems or components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components.*

Countable Event – *A failure of a component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System component configuration errors, or Protection System application errors are not included in Countable Events.*

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.

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4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.
5. If the Components in a Protection System Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

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Appendix QC-PRC-005-2 Provisions specific to the standard PRC-005-2 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:** Protection System Maintenance
2. **Number:** PRC-005-2
3. **Purpose:** No specific provision
4. **Applicability:**
 - 4.1. **Functions**
No specific provision
 - 4.2. **Facilities**
 - 4.2.1. Protection Systems that are installed for the purpose of detecting Faults on Bulk Power System (BPS) Elements (lines, busses, transformers, etc.).
 - 4.2.2. Protection Systems used for underfrequency load-shedding systems.
 - 4.2.3. Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BPS reliability.
 - 4.2.4. Protection System installed as a Special Protection System (SPS) for BPS reliability
 - 4.2.5. Protection Systems for generator Facilities that are part of the BPS, including :
 - 4.2.5.1. No specific provision
 - 4.2.5.2. Protection Systems for generator step-up transformers for generators that are part of BPS.
 - 4.2.5.3. Protection Systems for transformers connecting aggregated generation, where the aggregated generation is part of the BPS (e.g., transformers connecting facilities such as wind-farms to the BPS).
 - 4.2.5.4. Protection Systems for station service or excitation transformers connected to the generator bus of generator which are part of the BPS, that act to trip the generator either directly or via lockout or tripping auxiliary relays.
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. Evidence Retention

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Differences

No specific provision

F. Supplemental Reference Document

No specific provision

Table 1-1 to Table 1-5

No specific provision

Table 2

No specific provision

Table 3

No specific provision

Attachment A

No specific provision

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-NPCC-1
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
 - 4.1. Generator Owner
 - 4.2. Planning Coordinator
 - 4.3. Distribution Provider
 - 4.4. Transmission Owner
5. **Effective Date:** For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:

The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016. The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:

All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

B. Requirements

- R1** Each Planning Coordinator shall establish requirements for entities aggregating their UFLS programs for each anticipated island and requirements for compensatory load shedding based on islanding criteria (required by the NERC PRC Standard on UFLS). [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

- R2** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]
- R3** Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]
- R4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program reflecting normal operating conditions excluding outages for its Facilities based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3, or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1 and acting as a single entity, provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load, based on frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
- R5** Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
- 5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and
 - 5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations

from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

- 5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and
- 5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with the following minimum time delay:

- 7.1 Eastern Interconnection – 100 ms
- 7.2 Québec Interconnection – 200 ms

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R8 Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

- R9** Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
- R10** Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
- R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]
- R12** Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]
- R13** Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
- R14** Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
- R15** Each Generator Owner with a new generating unit, scheduled to be in service on or after the effective date of this Standard, or an existing generator increasing its net

capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is

required in Requirement R16.3 for generating units in its respective NPCC area.
[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

- 19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.
- 19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.
- 19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

R20 The Planning Coordinator shall update its UFLS program database as specified by the NERC PRC Standard on UFLS. This database shall include the following information: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

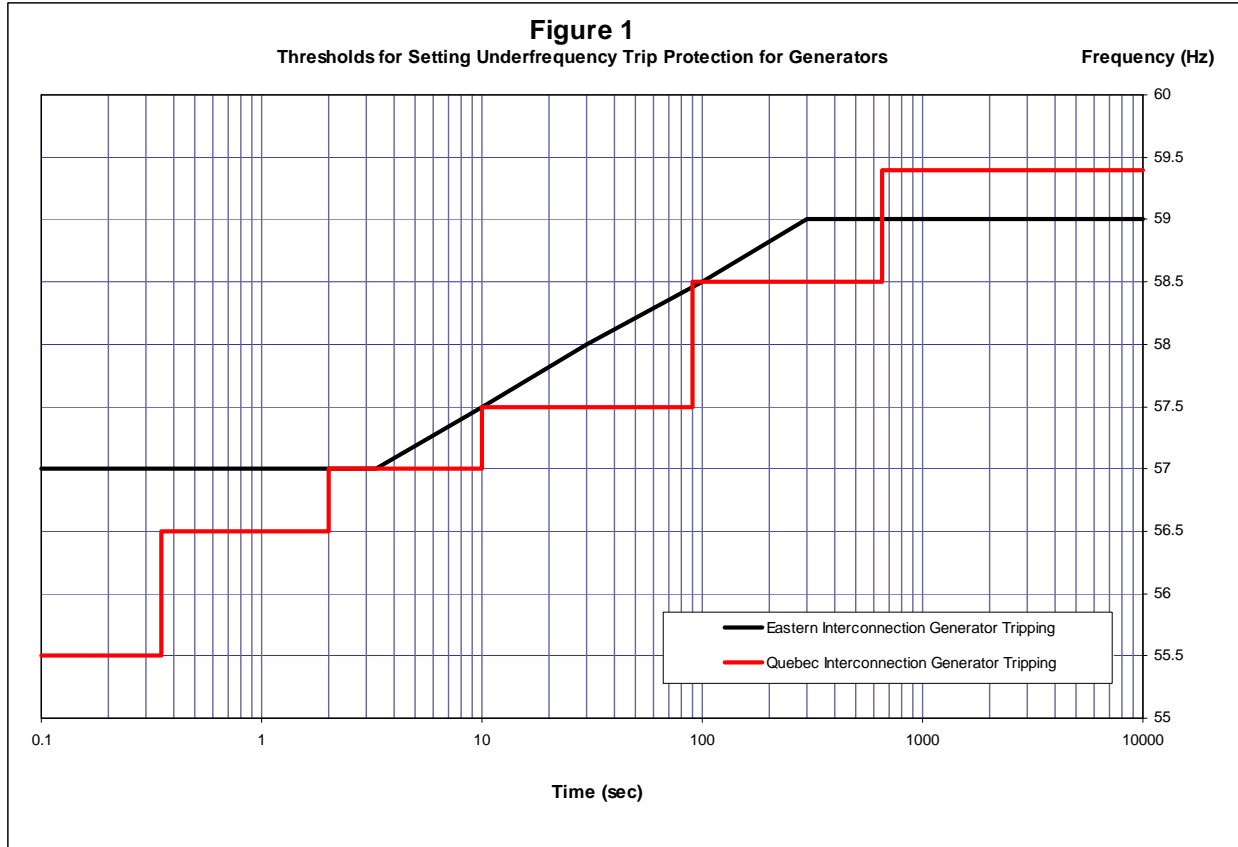
- 20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.
- 20.2 The buses at which the Load is modeled in the NPCC library power flow case.
- 20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.
- 20.4 The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.
- 20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load

distribution needed to satisfy UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R23 Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]



C. Measures

- M1** Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.
- M3** Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.
- M4** Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).
- M5** Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.
- M6** Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).
- M7** Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.
- M8** Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

- M9** Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.
- M10** Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.
- M11** Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.
- M12** Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.
- M13** Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.
- M14** Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.
- M15** Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.
- M16** Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.
- M17** Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that

demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested

				information.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.	solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	N/A	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

Standard PRC-006-NPCC-1 Automatic Underfrequency Load Shedding

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8	N/A	N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with

				Requirement R9.
R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12	N/A	N/A	N/A	The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in

				Figure 1, except as otherwise exempted.
R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75 days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of

			Requirement R16, Part 16.3.	Requirement R16, Part 16.3.
R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

Version History

Version	Date	Action	Change Tracking
1	November 20, 2011	Region BOD Approval	
1	February 9, 2012	Adopted by Board of Trustees	
1	February 21, 2013	Order issued by FERC approving PRC-006-NPCC-1 (approval effective April 29, 2013)	

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:
 - 1.1 Generator name and generating capacity
 - 1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
 - 1.3 Physical and electrical location of the unit
 - 1.4 All islands within which the unit may operate, as identified in Requirement R1
2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:
 - 2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.
 - 2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..
 - 2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting,

the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:
 - 1.1 Generator name and generating capacity
 - 1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
 - 1.3 Physical and electrical location of the unit
 - 1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.
2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:
 - 2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.
 - 2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.
 - 2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent ($\pm 5\%$) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection			
Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:			
Frequency Threshold (Hz)	Total Nominal Operating Time (s) ¹	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 31.5 –

UFLS Table 2: Eastern Interconnection				
Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:				
UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s) ¹	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s) ¹	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection					
	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s) ²
Threshold Stage 1	—	58.5	1000*	1000	0.30
Threshold Stage 2	—	58.0	800*	800	0.30
Threshold Stage 3	—	57.5	800	800	0.30
Threshold Stage 4	—	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	—	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

Appendix QC-PRC-006-NPCC-1 Provisions specific to the standard PRC-006-NPCC-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:** Automatic Underfrequency Load Shedding

2. **Number:** PRC-006-NPCC-1

3. **Purpose:** No specific provision

4. **Applicability:**

Functions:

4.1. Generator Owner that owns or operates an underfrequency load shedding program

4.2. No specific provision

4.3. Distribution Provider that owns or operates an underfrequency load shedding program

4.4. Transmission Owner that owns or operates an underfrequency load shedding program

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 monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Compliance Monitoring Period and Reset Time Frame

No specific provision

1.3. Data Retention

No specific provision

1.4. Compliance Monitoring and Assessment Processes

No specific provision

Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding

Appendix QC-PRC-006-NPCC-1

Provisions specific to the standard PRC-006-NPCC-1 applicable in Québec

1.5. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

PRC-006-NPCC-1 Attachment A

No specific provision

PRC-006-NPCC-1 Attachment B

No specific provision

PRC-006-NPCC-1 Attachment C

No specific provision

Revision History

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

A. Introduction

1. **Title:** **Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.**
2. **Number:** PRC-010-0
3. **Purpose:** Provide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.
4. **Applicability:**
 - 4.1. Load-Serving Entity that operates a UVLS program
 - 4.2. Transmission Owner that owns a UVLS program
 - 4.3. Transmission Operator that operates a UVLS program
 - 4.4. Distribution Provider that owns or operates a UVLS program
5. **Effective Date:** April 1, 2005

B. Requirements

- R1.** The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall periodically (at least every five years or as required by changes in system conditions) conduct and document an assessment of the effectiveness of the UVLS program. This assessment shall be conducted with the associated Transmission Planner(s) and Planning Authority(ies).
- R1.1.** This assessment shall include, but is not limited to:
- R1.1.1.** Coordination of the UVLS programs with other protection and control systems in the Region and with other Regional Reliability Organizations, as appropriate.
 - R1.1.2.** Simulations that demonstrate that the UVLS programs performance is consistent with Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0.
 - R1.1.3.** A review of the voltage set points and timing.
- R2.** The Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall provide documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC on request (30 calendar days). (Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1.** Each Transmission Owner's and Distribution Provider's UVLS program shall include the elements identified in Reliability Standard PRC-010-0_R1.
- M2.** Each Load-Serving Entity, Transmission Owner, Transmission Operator, and Distribution Provider that owns or operates a UVLS program shall have evidence it provided documentation of its current UVLS program assessment to its Regional Reliability Organization and NERC as specified in Reliability Standard PRC-010-0_R2. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

Assessments every five years or as required by System changes.

Current assessment on request (30 calendar days.)

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: An assessment of the UVLS program did not address one of the three requirements listed in Reliability Standard PRC-010-0_R1.1 or an assessment of the UVLS program was not provided.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	Adopted by NERC Board of Trustees	
0	March 16, 2007	Approved by FERC	
0	February 7, 2013	R2 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.	
0	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Standard PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program

Appendix QC-PRC-010-0

Provisions specific to the standard PRC-010-0 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:** Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program.
2. **Number:** PRC-010-0
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: Month xx 201x

B. Requirements

No specific provision

C. Measures

No specific provision

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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. Compliance Monitoring Period and Reset Timeframe

No specific provision

1.3. Data Retention

No specific provision

1.4. Additional Compliance Information

No specific provision

2. Levels of Non-Compliance

No specific provision

E. Regional Differences

No specific provision

Standard PRC-010-0 — Assessment of the Design and Effectiveness of UVLS Program

Appendix QC-PRC-010-0

Provisions specific to the standard PRC-010-0 applicable in Québec

Revision History

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

A. Introduction

1. **Title:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
2. **Number:** PRC-019-1
3. **Purpose:** To verify coordination of generating unit Facility or synchronous condenser voltage regulating controls, limit functions, equipment capabilities and Protection System settings.

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 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

4.2.3 Generating plant/ Facility consisting of one or more units that are connected to the Bulk Electric System at a common bus with total generation greater than 75 MVA (gross aggregate nameplate rating).

4.2.4 Any generator, regardless of size, that is a blackstart unit material to and designated as part of a Transmission Operator’s restoration plan.

5. **Effective Date:**

5.1. In those jurisdictions where regulatory approval is required:

5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner 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, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, approval each

Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

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 required:

5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees 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.

5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees 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.

5.2.3 By the first day of the first calendar quarter, four calendar years following Board of Trustees 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 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, 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.

B. Requirements

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service¹ limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions. [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

¹ Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

- 1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.
 - 1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.
 - R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following [*Violation Risk Factor: Medium*] [*Time Horizon: Long-term Planning*]:
 - Voltage regulating settings or equipment changes;
 - Protection System settings or component changes;
 - Generating or synchronous condenser equipment capability changes; or
 - Generator or synchronous condenser step-up transformer changes.

C. Measures

- M1. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence (such as examples provided in PRC-019 Section G) that it coordinated the voltage regulating system controls, including in-service² limiters and protection functions, with the applicable equipment capabilities and settings of the applicable Protection System devices and functions as specified in Requirement R1. This evidence should include dated documentation that demonstrates the coordination was performed.
- M2. Each Generator Owner and Transmission Owner with applicable Facilities will have evidence of the coordination required by the events listed in Requirement R2. This evidence should include dated documentation that demonstrates the specified intervals in Requirement R2 have been met.

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.

² Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

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 retain evidence of compliance with Requirements R1 and R2, Measures M1 and M2 for six years.

If a Generator Owner or Transmission Owner is found non-compliant, the entity shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 5 calendar	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 5 calendar

Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

	years but less than or equal to 5 calendar years plus 4 months after the previous coordination.	years plus 4 months but less than or equal to 5 calendar years plus 8 months after the previous coordination.	years plus 8 months but less than or equal to 5 calendar years plus 12 months after the previous coordination.	years plus 12 months after the previous coordination.
R2	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 90 calendar days but less than or equal to 100 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 100 calendar days but less than or equal to 110 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner coordinated equipment capabilities, limiters, and protection specified in Requirement R1 more than 110 calendar days but less than or equal to 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.	The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection specified in Requirement R1 within 120 calendar days following the identification or implementation of a change in equipment or settings that affected the coordination.

E. Regional Variances

None.

F. Associated Documents

“Underexcited Operation of Turbo Generators”, AIEE Proceedings T Section 881, Volume 67, 1948, Appendix 1, C. G. Adams and J. B. McClure.

,”Protective Relaying For Power Generation Systems”, Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald

“Coordination of Generator Protection with Generator Excitation Control and Generator Capability”, a report of Working Group J5 of the IEEE PSRC Rotating Machinery Subcommittee

“IEEE C37.102-2006 IEEE Guide for AC Generator Protection”

“IEEE C50.13-2005 IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above”

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 PRC-019-1. (Order becomes effective on 7/1/16.)	

G. Reference

Examples of Coordination

The evidence of coordination associated with Requirement R1 may be in the form of:

- P-Q Diagram (Example in Attachment 1), or
- R-X Diagram (Example in Attachment 2), or
- Inverse Time Diagram (Example in Attachment 3) or,
- Equivalent tables or other evidence

This evidence should include the equipment capabilities and the operating region for the limiters and protection functions

Equipment limits, types of limiters and protection functions which could be coordinated include (but are not limited to):

- Field over-excitation limiter and associated protection functions.
- Inverter over current limit and associated protection functions.
- Field under-excitation limiter and associated protection functions.
- Generator or synchronous condenser reactive capabilities.
- Volts per hertz limiter and associated protection functions.
- Stator over-voltage protection system settings.
- Generator and transformer volts per hertz capability.
- Time vs. field current or time vs. stator current.

Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

NOTE: This listing is for reference only. This standard does not require the installation or activation of any of the above limiter or protection functions.

For this example, the Steady State Stability Limit (SSSL) is the limit to synchronous stability in the under-excited region with fixed field current.

On a P-Q diagram using X_d as the direct axis saturated synchronous reactance of the generator, X_s as the equivalent reactance between the generator terminals and the “infinite bus” including the reactance of the generator step-up transformer and V_g as the generator terminal voltage (all values in per-unit), the SSSL can be calculated as an arc with the center on the Q axis with the magnitude of the center and radius described by the following equations

$$C = V_g^2/2*(1/X_s-1/X_d)$$

$$R = V_g^2/2*(1/X_s+1/X_d)$$

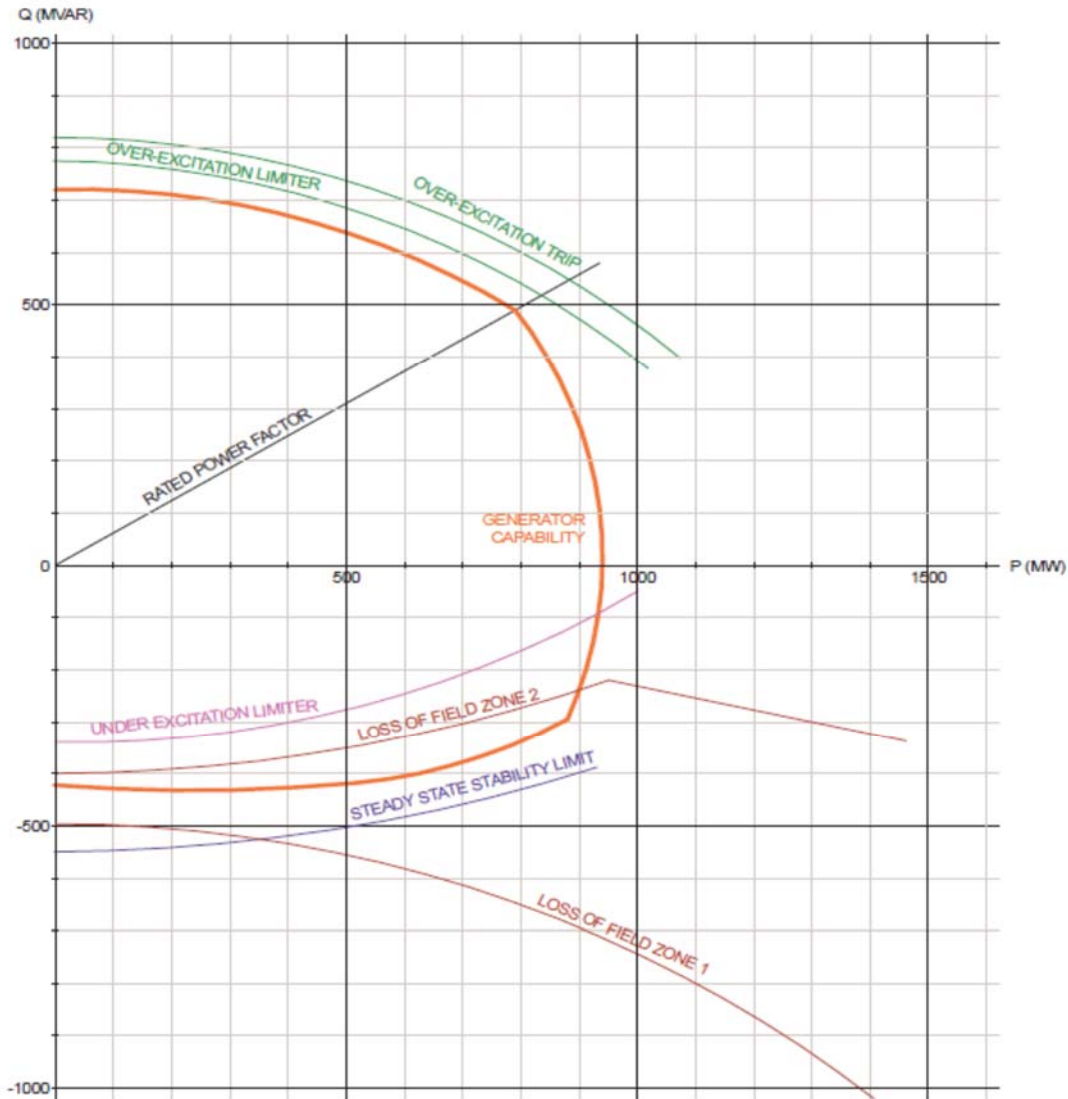
On an R-X diagram using X_d as the direct axis saturated synchronous reactance of the generator, and X_s as the equivalent reactance between the generator terminals and the “infinite bus” including the reactance of the generator step-up transformer the SSSL is an arc with the center on the X axis with the center and radius described by the following equations:

$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

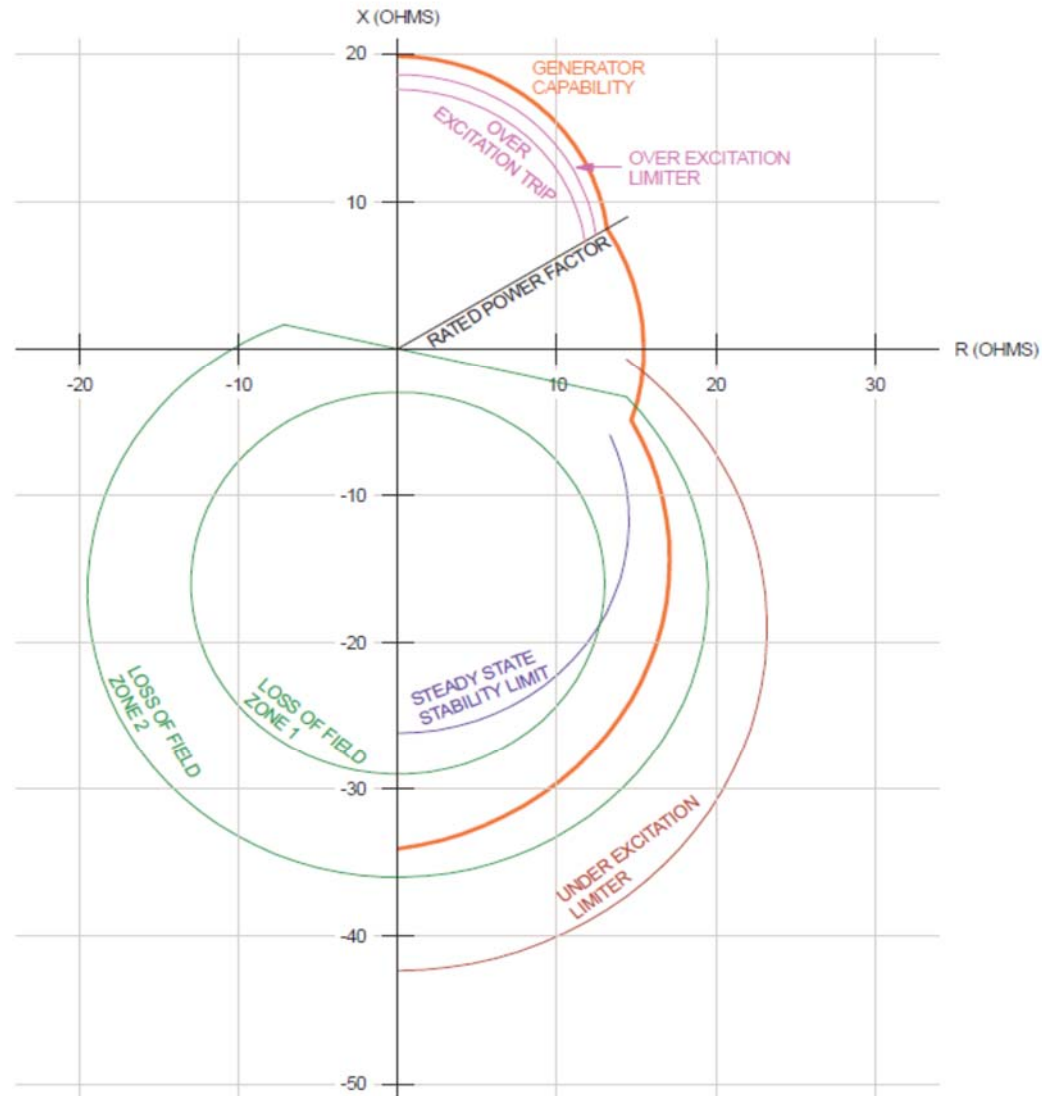
Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



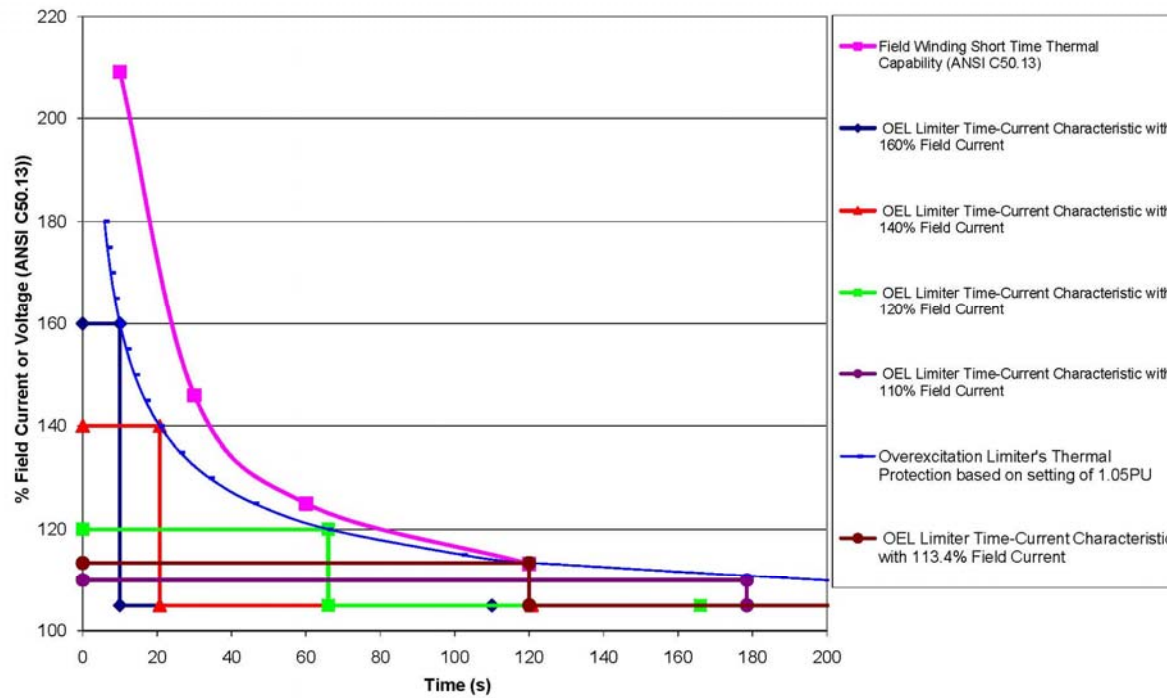
Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Appendix QC-PRC-019-1 Provisions specific to the standard PRC-019-1 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:** Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
2. **Number:** PRC-019-1
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).
 - 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

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 Enforcement Processes:**
No specific provision

Standard PRC-019-1 — Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

**Appendix QC-PRC-019-1
Provisions specific to the standard PRC-019-1 applicable in Québec**

1.4. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Differences

No specific provision

F. Associated Documents

No specific provision

G. Reference

No specific provisions

Section G Attachment 1

No specific provision

Section G Attachment 2

No specific provision

Section G Attachment 3

No specific provision

Revision History

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

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance

A. Introduction

1. **Title:** Under-Voltage Load Shedding Program Performance
2. **Number:** PRC-022-1
3. **Purpose:** Ensure that Under Voltage Load Shedding (UVLS) programs perform as intended to mitigate the risk of voltage collapse or voltage instability in the Bulk Electric System (BES).
4. **Applicability**
 - 4.1. Transmission Operator that operates a UVLS program.
 - 4.2. Distribution Provider that operates a UVLS program.
 - 4.3. Load-Serving Entity that operates a UVLS program.
5. **Effective Date:** May 1, 2006

B. Requirements

- R1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include:
 - R1.1. A description of the event including initiating conditions.
 - R1.2. A review of the UVLS set points and tripping times.
 - R1.3. A simulation of the event, if deemed appropriate by the Regional Reliability Organization. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.
 - R1.4. A summary of the findings.
 - R1.5. For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.
- R2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall provide documentation of its analysis of UVLS program performance to its Regional Reliability Organization within 90 calendar days of a request. (Retirement approved by FERC effective January 21, 2014.)

C. Measures

- M1. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have documentation of its analysis of UVLS operations and Misoperations in accordance with Requirement 1.1 through 1.5.
- M2. Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall have evidence that it provided documentation of its analysis of UVLS program performance within 90 calendar days of a request by the Regional Reliability Organization. (Retirement approved by FERC effective January 21, 2014.)

D. Compliance

1. Compliance Monitoring Process
 - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program shall retain documentation of its analyses of UVLS operations and Misoperations for two years. The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

Transmission Operator, Load-Serving Entity, and Distribution Provider shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: Documentation of the analysis of UVLS performance was provided but did not include one of the five requirements in R1.

2.3. Level 3: Documentation of the analysis of UVLS performance was provided but did not include two or more of the five requirements in R1.

2.4. Level 4: Documentation of the analysis of UVLS performance was not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	December 1, 2005	<ol style="list-style-type: none"> 1. Removed comma after 2004 in “Development Steps Completed,” #1. 2. Changed incorrect use of certain hyphens (-) to “en dash” (–) and “em dash (—).” 3. Lower cased the word “region,” “board,” and “regional” throughout document where appropriate. 4. Added or removed “periods” where appropriate. 5. Changed “Timeframe” to “Time Frame” in item D, 1.2. 	January 20, 2006
1	February 7, 2006	Adopted by the NERC Board of Trustees	
1	March 16, 2007	Approved by FERC	
1	February 7, 2013	R2 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending	

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance

		applicable regulatory approval.	
1	November 21, 2013	R2 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance

Appendix QC-PRC-022-1

Provisions specific to the standard PRC-022-1 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:** Under-Voltage Load Shedding Program Performance
2. **Number:** PRC-022-1
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: Month xx 201x

B. Requirements

- R1. No specific provision
 - R1.1 No specific provision
 - R1.2 No specific provision
 - R1.3 A simulation of the event, if deemed appropriate by the Régie de l'énergie. For most events, analysis of sequence of events may be sufficient and dynamic simulations may not be needed.
 - R1.4 No specific provision
- R2. No specific provision

C. Measures

No specific provision

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

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. **Compliance Monitoring Period and Reset Time Frame**

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

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

No specific provision

Standard PRC-022-1 — Under-Voltage Load Shedding Program Performance

Appendix QC-PRC-022-1

Provisions specific to the standard PRC-022-1 applicable in Québec

2. Levels of Non-Compliance

No specific provision

E. Regional Differences

No specific provision

Revision History

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

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-3
3. **Purpose:** Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. **Applicability:**
 - 4.1. **Functional Entity:**
 - 4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
 - 4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*).
 - 4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (*Circuits Subject to Requirements R1 – R5*), provided those circuits have bi-directional flow capabilities.
 - 4.1.4 Planning Coordinator
 - 4.2. **Circuits:**
 - 4.2.1 **Circuits Subject to Requirements R1 – R5:**
 - 4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
 - 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.
 - 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
 - 4.2.2 **Circuits Subject to Requirement R6:**
 - 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. [*Violation Risk Factor: High*] [*Time Horizon: Long Term Planning*].

Criteria:

1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating¹ of a circuit (expressed in amperes).
3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:
 - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
 - An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.
4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:
 - 115% of the highest emergency rating of the series capacitor.
 - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.
5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).
6. Not used.

¹ When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.
8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.
9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.
10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of:
 - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
 - 115% of the highest operator established emergency transformer rating.
- 10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability².
11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 10 set the relays according to one of the following:
 - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.
 - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature³.
12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:
 - a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.
 - b. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.
 - c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

² As illustrated by the “dotted line” in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

³ IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

- 13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.
- R2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*
- R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*
- R6.** Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
- 6.1** Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.
- 6.2** Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

- M1.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

- M2.** Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)
- M3.** Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)
- M4.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)
- M5.** Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)
- M6.** Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

If a Transmission Owner, Generator Owner, Distribution Provider, or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

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

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	<p>The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions.</p> <p>OR</p> <p>The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.</p>
R2	N/A	N/A	N/A	<p>The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.</p>
R3	N/A	N/A	N/A	<p>The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.</p>

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Requirement	Lower	Moderate	High	Severe
				<p>OR</p> <p>The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.</p>
R4	N/A	N/A	N/A	<p>The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.</p>
R5	N/A	N/A	N/A	<p>The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.</p>
R6	N/A	<p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more</p>	<p>The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24</p>	<p>The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>

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Requirement	Lower	Moderate	High	Severe
		<p>than 15 months and less than 24 months lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.</p>	<p>months or more lapsed between assessments.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)</p>	<p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2.</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1)</p> <p>OR</p> <p>The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met</p>

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Requirement	Lower	Moderate	High	Severe
		(part 6.2)		<p>6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2)</p> <p>OR</p> <p>The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.</p>

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies.

“Determination and Application of Practical Relaying Loadability Ratings,” Version 1.0, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at:

http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

PRC-023-3 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
 - 1.1. Phase distance.
 - 1.2. Out-of-step tripping.
 - 1.3. Switch-on-to-fault.
 - 1.4. Overcurrent relays.
 - 1.5. Communications aided protection schemes including but not limited to:
 - 1.5.1 Permissive overreach transfer trip (POTT).
 - 1.5.2 Permissive under-reach transfer trip (PUTT).
 - 1.5.3 Directional comparison blocking (DCB).
 - 1.5.4 Directional comparison unblocking (DCUB).
 - 1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.
2. The following protection systems are excluded from requirements of this standard:
 - 2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
 - Overcurrent elements that are only enabled during loss of potential conditions.
 - Elements that are only enabled during a loss of communications except as noted in section 1.6.
 - 2.2. Protection systems intended for the detection of ground fault conditions.
 - 2.3. Protection systems intended for protection during stable power swings.
 - 2.4. Not used.
 - 2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.
 - 2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.
 - 2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
 - 2.8. Relay elements associated with dc lines.
 - 2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- B1.** The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- B2.** The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.
- B3.** The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- B4.** The circuit is identified through the following sequence of power flow analyses⁴ performed by the Planning Coordinator for the one-to-five-year planning horizon:
- a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
 - b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
 - c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
 - d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

⁴ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

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- i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
 - ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
 - iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
 - e. Radially operated circuits serving only load are excluded.
- B5.** The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.
- B6.** The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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Appendix QC-PRC-023-3 Provisions specific to the standard PRC-023-3 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:** Transmission Relay Loadability
2. **Number:** PRC-023-3
3. **Purpose:** No specific provision
4. **Applicability:**
 - 4.1. **Functional Entity:**
No specific provision
 - 4.2. **Circuits:**
The 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

- R1. Specific provision applicable to criterion 10:**
Replace the setting value of 115% by 105%.
- R5.** Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to the Régie de l'énergie at last once each calendar year, with no more than 15 months between reports, to allow this one to compile a list of all circuits that have protective relay settings that limit circuit capability.

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 monitoring with respect to the reliability standard and its appendix that it adopts.
 - 1.2 **Data Retention**
No specific provision
 - 1.3 **Compliance Monitoring and Assessment Process**
No specific provision

Standard PRC-023-3 — Transmission Relay Loadability

Appendix QC-PRC-023-3

Provisions specific to the standard PRC-023-3 applicable in Québec

1.4 Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Differences

No specific provision

F. Supplemental Technical Reference Document

No specific provision

PRC-023 – Appendix A

No specific provision

PRC-023 – Appendix B

No specific provision

Revision History

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

A. Introduction

1. **Title:** Generator Frequency and Voltage Protective Relay Settings
2. **Number:** PRC-024-1
3. **Purpose:** Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
4. **Applicability:**
 - 4.1. Generator Owner
5. **Effective Date:**
 - 5.1. In those jurisdictions where regulatory approval is required:
 - 5.1.1 By the first day of the first calendar quarter, two calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.2 By the first day of the first calendar quarter, three calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.3 By the first day of the first calendar quarter, four calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.1.4 By the first day of the first calendar quarter, five calendar years following applicable regulatory approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.2. In those jurisdictions where regulatory approval is not required:
 - 5.2.1 By the first day of the first calendar quarter, two calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 40 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
 - 5.2.2 By the first day of the first calendar quarter, three calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 60 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

- 5.2.3** By the first day of the first calendar quarter, four calendar years following Board of Trustees approval, each Generator Owner shall have verified at least 80 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.
- 5.2.4** By the first day of the first calendar quarter, five calendar years following Board of Trustees approval, each Generator Owner shall have verified 100 percent of its Facilities are fully compliant with Requirements R1, R2, R3, and R4.

B. Requirements

- R1.** Each Generator Owner that has generator frequency protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator frequency protective relaying does not trip the applicable generating unit(s) within the “no trip zone” of PRC-024 Attachment 1, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 1 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R2.** Each Generator Owner that has generator voltage protective relaying¹ activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection²) caused by an event on the transmission system external to the generating plant that remains within the “no trip zone” of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner’s study. Requirement R2 is subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
- Generating unit(s) may trip in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS).
 - Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).
 - Generating unit(s) may trip by action of protective functions (such as out-of-step functions or loss-of-field functions) that operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

¹ Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

² For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

- Generating unit(s) may trip within a portion of the “no trip zone” of PRC-024 Attachment 2 for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- R3.** Each Generator Owner shall document each known regulatory or equipment limitation³ that prevents an applicable generating unit with generator frequency or voltage protective relays from meeting the relay setting criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer’s advice.
[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]
- 3.1.** The Generator Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:
- Identification of a regulatory or equipment limitation.
 - Repair of the equipment causing the limitation that removes the limitation.
 - Replacement of the equipment causing the limitation with equipment that removes the limitation.
 - Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.
- R4.** Each Generator Owner shall provide its applicable generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated unit within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

C. Measures

- M1.** Each Generator Owner shall have evidence that generator frequency protective relays have been set in accordance with Requirement R1 such as dated setting sheets, calibration sheets or other documentation.
- M2.** Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots, dynamic simulation studies or other documentation.
- M3.** Each Generator Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations (excluding limitations noted in footnote 3) that resulted in an exception to Requirements R1 or R2 in accordance with Requirement

³ Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect.

R3 such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer’s advice.

- M4.** Each Generator Owner shall have evidence that it communicated applicable generator protective relay trip settings in accordance with Requirement R4, such as dated e-mails, correspondence or other evidence and copies of any requests it has received for that information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

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

The Generator Owner shall retain evidence of compliance with Requirement R1 through R4; for 3 years or until the next audit, whichever is longer.

If a Generator Owner is found non-compliant, the Generator Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings

2. Violation Severity Levels

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	The Generator Owner that has frequency protection activated to trip a generating unit, failed to set its generator frequency protective relaying so that it does not trip within the criteria listed in Requirement R1 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R2	N/A	N/A	N/A	The Generator Owner with voltage protective relaying activated to trip a generating unit, failed to set its voltage protective relaying so that it does not trip as a result of a voltage excursion at the point of interconnection, caused by an event external to the plant per the criteria specified in Requirement R2 unless there is a documented and communicated regulatory or equipment limitation per Requirement R3.
R3	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner	The Generator Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner failed to communicate

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings

R #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar days of identifying the limitation.
R4	<p>The Generator Owner provided its generator protection trip settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner provided trip settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.</p>	<p>The Generator Owner provided its generator protection trip settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner provided trip settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.</p>	<p>The Generator Owner provided its generator protection trip settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner provided trip settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.</p>	<p>The Generator Owner failed to provide its generator protection trip settings within 150 calendar days of any change to those trip settings.</p> <p>OR</p> <p>The Generator Owner failed to provide trip settings within 150 calendar days of a written request.</p>

E. Regional Variances

None

F. Associated Documents

None

Version History

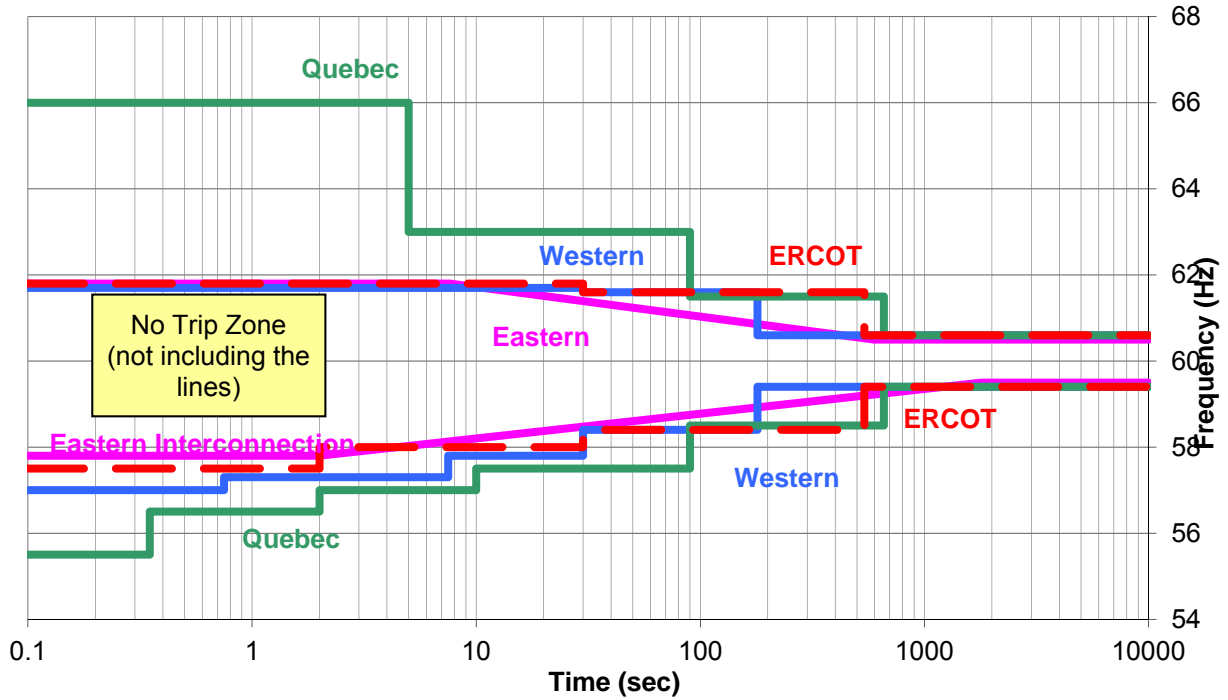
Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	

G. References

1. “The Technical Justification for the New WECC Voltage Ride-Through (VRT) Standard, A White Paper Developed by the Wind Generation Task Force (WGTF),” dated June 13, 2007, a guideline approved by WECC Technical Studies Subcommittee.

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Curve Data Points:

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings

Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.7	Instantaneous trip	≤57.0	Instantaneous trip
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

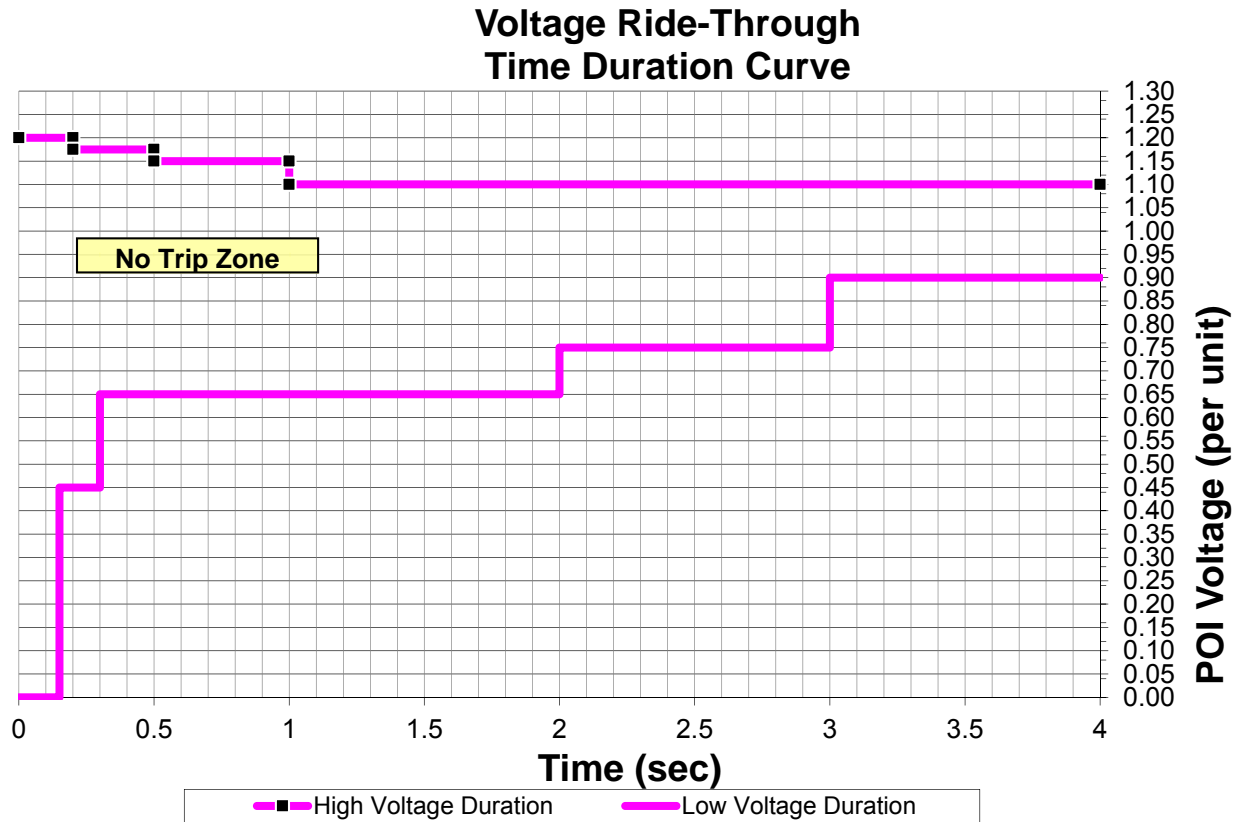
Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (Sec)
>66.0	Instantaneous trip	<55.5	Instantaneous trip
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.5	Instantaneous trip
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024— Attachment 2



Ride Through Duration:

High Voltage Ride Through Duration		Low Voltage Ride Through Duration	
Voltage (pu)	Time (sec)	Voltage (pu)	Time (sec)
≥1.200	Instantaneous trip	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00

Voltage Ride-Through Curve Clarifications

Curve Details:

1. The per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).
2. The curves depicted were derived based on three-phase transmission system zone 1 faults with Normal Clearing not exceeding 9 cycles. The curves apply to voltage excursions regardless of the type of initiating event.
3. The envelope within the curves represents the cumulative voltage duration at the point of interconnection with the BES. For example, if the voltage first exceeds 1.15 pu at 0.3 seconds after a fault, does not exceed 1.2 pu voltage, and returns below 1.15 pu at 0.4 seconds, then the cumulative time the voltage is above 1.15 pu voltage is 0.1 seconds and is within the no trip zone of the curve.
4. The curves depicted assume system frequency is 60 Hertz. When evaluating Volts/Hertz protection, you may adjust the magnitude of the high voltage curve in proportion to deviations of frequency below 60 Hz.
5. Voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.

Evaluating Protective Relay Settings:

1. Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions:
 - a. All of the units connected to the same transformer are online and operating.
 - b. All of the units are at full nameplate real-power output.
 - c. Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals.
 - d. The automatic voltage regulator is in automatic voltage control mode.
2. Evaluate voltage protection relay settings assuming that additional installed generating plant reactive support equipment (such as static VAr compensators, synchronous condensers, or capacitors) is available and operating normally.
3. Evaluate voltage protection relay settings accounting for the actual tap settings of transformers between the generator terminals and the point of interconnection.

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings

Appendix QC-PRC-024-1

Provisions specific to the standard PRC-024-1 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:** Generator Frequency and Voltage Protective Relay Settings

2. **Number:** PRC-024-1

3. **Purpose:** No specific provision

4. **Applicability:**

Functions

No specific provision

Facilities

The 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 Monitoring 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. **Data 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

Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings

Appendix QC-PRC-024-1

Provisions specific to the standard PRC-024-1 applicable in Québec

E. Regional Variances

No specific provision

F. Associated Document

No specific provision

G. References

No specific provisions

PRC-024-1 — Attachment 1

No specific provision

PRC-024-1 — Attachment 2

No specific provision

Revision History

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

A. Introduction

1. **Title:** Generator Relay Loadability

2. **Number:** PRC-025-1

Purpose: To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

3. **Applicability:**

3.1. Functional Entities:

3.1.1 Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.2 Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.1.3 Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

3.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator’s system restoration plan:

3.2.1 Generating unit(s).

3.2.2 Generator step-up (i.e., GSU) transformer(s).

3.2.3 Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.¹

3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

3.2.5 Elements utilized in the aggregation of dispersed power producing resources.

4. **Background:**

After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that

¹ These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-1 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

disturbance. This was noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.²

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

5. **Effective Date:** See Implementation Plan

B. Requirements and Measures

- R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. [*Violation Risk Factor: High*] [*Time Horizon: Long-Term Planning*]
- M1.** For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-1 – Attachment 1: Relay Settings.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

² Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (<http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf>)

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

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

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with <i>PRC-025-1 – Attachment 1: Relay Settings</i> , on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, “Power Plant and Transmission System Protection Coordination.”

IEEE C37.102-2006, “Guide for AC Generator Protection.”

PRC-025-1 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay pickup setting criteria values are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Asynchronous generator relay pickup setting criteria values (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads.), the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Special Protection Systems that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of fullload current (e.g., rated armature current), and prevent operation below 115% of full-load current.³
7. Protection systems that detect transformer overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 beginning on the next page is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant

³ IEEE C37.102-2006, “Guide for AC Generator Protection,” Section 4.1.1.2.

loads). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

⁴ Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Synchronous generating unit(s), or Elements utilized in the aggregation of dispersed power producing resources	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
	2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation		
The same application continues with a different relay type below					
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), or Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) or (51V-R) – voltage-restrained	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 14	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 15	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 16	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 17	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 18	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of the GSU transformer If the relay is installed on the high-side of the GSU transformer use Option 19	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)	
A different application starts below					
Unit auxiliary transformer(s) (UAT)	Phase time overcurrent relay (51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating	
		OR			
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on the high-side of the GSU transformer	14a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
	If the relay is installed on the generator-side of the GSU transformer use Option 7	14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
The same application continues on the next page with a different relay type				

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to synchronous generators	Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) – installed on the high-side of the GSU transformer If the relay is installed on the generator-side of the GSU transformer use Option 8	15a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
The same application continues on the next page with a different relay type					

Table 1. Relay Loadability Evaluation Criteria					
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria	
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant load. – connected to synchronous generators	Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or phase directional time overcurrent relay (67) – directional toward the Transmission system installed on the high-side of the GSU transformer	16a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor	
		OR			
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation	
A different application starts on the next page					

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system– installed on the high-side of the GSU transformer	17	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	If the relay is installed on the generator-side of the GSU transformer use Option 10			
The same application continues on the next page with a different relay type				

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
<p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p>	<p>Phase overcurrent supervisory element (50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or Phase time overcurrent relay (51) – installed on the high-side of the GSU transformer</p>	18	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	<p>The same application continues on the next page with a different relay type</p>			

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage ⁴	Pickup Setting Criteria
<p>Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. – connected to asynchronous generators only (including inverter-based installations)</p>	<p>Phase directional overcurrent supervisory element (67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer or Phase directional time overcurrent relay (67) – installed on the high-side of the GSU transformer</p> <p>If the relay is installed on the generator-side of the GSU transformer use Option 12</p>	19	1.0 per unit of the line nominal voltage	<p>The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)</p>
End of Table 1				

Rationale:

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

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New

Standard PRC-025-1 — Generator Relay Loadability

Appendix QC-PRC-025-1 Provisions specific to the standard PRC-025-1 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:** Generator Relay Loadability
2. **Number:** PRC-025-1
Purpose: No specific provision
3. **Applicability:**
 - 3.1. **Functional Entity:**
No specific provision
 - 3.2. **Facilities:** The following Elements associated with Main Transmission System (RTP) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:
 - 3.2.1 No specific provision.
 - 3.2.2 No specific provision.
 - 3.2.3 No specific provision.
 - 3.2.4 Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a RTP generating unit or generating plant. Elements may also supply generating plant loads.
 - 3.2.5 No specific provision.
4. **Background**
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 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.

Standard PRC-025-1 — Generator Relay Loadability

Appendix QC-PRC-025-1

Provisions specific to the standard PRC-025-1 applicable in Québec

1.2 Evidence Retention

No specific provision

1.3 Compliance Monitoring and Assessment Process

No specific provision

1.4 Additional Compliance Information

No specific provision

Table of Compliance Elements

No specific provision

D. Regional Differences

No specific provision

E. Interpretations

No specific provision

F. Associated documents

No specific provision

PRC-025-1 – Attachment 1: Relays Settings

No specific provision

Table 1

No specific provision

Rationale

No specific provision

Revision History

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

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements
2. **Number:** TPL-001-4
3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. **Applicability:**
 - 4.1. **Functional Entity**
 - 4.1.1. Planning Coordinator.
 - 4.1.2. Transmission Planner.
5. **Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

B. Requirements

- R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 1.1.** System models shall represent:
- 1.1.1.** Existing Facilities
 - 1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
 - 1.1.3.** New planned Facilities and changes to existing Facilities
 - 1.1.4.** Real and reactive Load forecasts
 - 1.1.5.** Known commitments for Firm Transmission Service and Interchange
 - 1.1.6.** Resources (supply or demand side) required for Load
- R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*
- 2.1.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:
- 2.1.1.** System peak Load for either Year One or year two, and for year five.
 - 2.1.2.** System Off-Peak Load for one of the five years.
 - 2.1.3.** P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.
 - 2.1.4.** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response :
 - Real and reactive forecasted Load.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- Controllable Loads and Demand Side Management.
 - Duration or timing of known Transmission outages.
- 2.1.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- 2.2.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
- 2.2.1.** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.
- 2.3.** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.
- 2.4.** For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:
- 2.4.1.** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.
- 2.4.2.** System Off-Peak Load for one of the five years.
- 2.4.3.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:
- Load level, Load forecast, or dynamic Load model assumptions.
 - Expected transfers.
 - Expected in service dates of new or modified Transmission Facilities.
 - Reactive resource capability.
 - Generation additions, retirements, or other dispatch scenarios.

- 2.5.** For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.
- 2.6.** Past studies may be used to support the Planning Assessment if they meet the following requirements:
- 2.6.1.** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
- 2.6.2.** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.
- 2.7.** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:
- 2.7.1.** List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
 - Installation, modification, or removal of Protection Systems or Special Protection Systems
 - Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
 - Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
 - Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
 - Use of rate applications, DSM, new technologies, or other initiatives.
- 2.7.2.** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.
- 2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

- a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
- b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
- c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

- f. Applicable Facility Ratings shall not be exceeded.
- g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
- h. Planning event P0 is applicable to steady state only.
- i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

- j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault ⁷	N/A	EHV, HV	No ⁹	No ¹²
		2. Bus Section Fault	SLG	EHV	No ⁹	No
				HV	Yes	Yes
		3. Internal Breaker Fault ⁸ (non-Bus-tie Breaker)	SLG	EHV	No ⁹	No
HV	Yes			Yes		
4. Internal Breaker Fault (Bus-tie Breaker) ⁸	SLG	EHV, HV	Yes	Yes		

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Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments ⁹	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶	3Ø	EHV, HV	No ⁹	No ¹²
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency <i>(Fault plus stuck breaker¹⁰)</i>	Normal System	Loss of multiple elements caused by a stuck breaker ¹⁰ (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section	SLG	EHV	No ⁹	No
		6. Loss of multiple elements caused by a stuck breaker ¹⁰ (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	HV	Yes	Yes
			SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency <i>(Fault plus relay failure to operate)</i>	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay ¹³ protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁵ 4. Shunt Device ⁶ 5. Bus Section	SLG	EHV	No ⁹	No
				HV	Yes	Yes
P6 Multiple Contingency <i>(Two overlapping singles)</i>	Loss of one of the following followed by System adjustments. ⁹ 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶ 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer ⁵ 3. Shunt Device ⁶	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

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Category	Initial Condition	Event ¹	Fault Type ²	BES Level ³	Interruption of Firm Transmission Service Allowed ⁴	Non-Consequential Load Loss Allowed
P7 Multiple Contingency <i>(Common Structure)</i>	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure ¹¹ 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

- a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
- b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
 - a. Loss of a tower line with three or more circuits.¹¹
 - b. Loss of all Transmission lines on a common Right-of-Way¹¹.
 - c. Loss of a switching station or substation (loss of one voltage level plus transformers).
 - d. Loss of all generating units at a generating station.
 - e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
 - a. Loss of two generating stations resulting from conditions such as:
 - i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
 - ii. Loss of the use of a large body of water as the cooling source for generation.
 - iii. Wildfires.
 - iv. Severe weather, e.g., hurricanes, tornadoes, etc.
 - v. A successful cyber attack.
 - vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
 - b. Other events based upon operating experience that may result in wide area disturbances.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
 - a. 3Ø fault on generator with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing.
 - b. 3Ø fault on Transmission circuit with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing.
 - c. 3Ø fault on transformer with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing.
 - d. 3Ø fault on bus section with stuck breaker¹⁰ or a relay failure¹³ resulting in Delayed Fault Clearing.
 - e. 3Ø internal breaker fault.
 - f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

**Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)**

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, &

**Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)**

67), and tripping (#86, & 94).

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
 - a. Date, time, and location for the meeting
 - b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
 - c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
 - a. System Load level and estimated annual hours of exposure at or above that Load level
 - b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
 - a. The estimated number and type of customers affected

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- b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community
3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance
4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance
5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12
6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12
7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12
8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
 - a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
 - b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)
2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

C. Measures

- M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.
- M3.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not applicable.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4 Data Retention

The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.
- The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.
- The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.

If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

1.5 Additional Compliance Information

None

2. Violation Severity Levels

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.
R2	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.
R3	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.

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	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</p>	<p>Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</p>	<p>OR</p> <p>The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>
R4	<p>The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.</p>	<p>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.</p> <p>OR</p> <p>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</p>
R5	N/A	N/A	N/A	<p>The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.</p>
R6	N/A	N/A	N/A	<p>The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.</p>

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	Lower VSL	Moderate VSL	High VSL	Severe VSL
R7	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.
R8	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.</p> <p>OR,</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.</p>	<p>The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.</p> <p>OR</p> <p>The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.</p> <p>OR</p> <p>The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.</p>

E. Regional Variances

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Appendix QC-TPL-001-4

Provisions specific to the standard TPL-001-4 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: Transmission System Planning Performance Requirements

2. Number: TPL-001-4

3. Purpose: No specific provision

4. Applicability:

4.1. Functional entities

No specific provision

Facilities

This standard only applies to the facilities of the Bulk Power System (BPS)

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 monitoring with respect to the reliability standard and its appendix that it adopts.

1.2. Compliance Monitoring Period and Reset Timeframe

No specific provision

1.3. Compliance Monitoring and Enforcement Processes:

No specific provision

1.4. Data Retention

No specific provision

Standard TPL-001-4 — Transmission System Planning Performance Requirements

Appendix QC-TPL-001-4

Provisions specific to the standard TPL-001-4 applicable in Québec

1.5. Additional Compliance Information

No specific provision

2. Violation Severity Levels

No specific provision

E. Regional Variances

No specific provision

Table 1

This table only applies to the facilities of the Bulk Power System (BPS) for:

- Categories
- Contingencies
- System Limits or Impacts

Attachment 1

No specific provision

Revision History

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

A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
 - 4.1. Transmission Operators
 - 4.2. Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date:**
 - 5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, 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.

B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. *[Violation Risk Factor: High] [Time Horizon: Operational Planning]*

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Planning]*

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

4.1 If a Transmission Operator determines that a generator has satisfied the exemption criteria, it shall notify the associated Generator Operator.

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt from: 1) following a voltage or Reactive Power schedule, 2) from having its

automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

- R5.** Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator's discretion. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
- 5.1.** The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).
- 5.2.** The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
- 5.3.** The Transmission Operator shall provide the criteria used to develop voltage schedules Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.
- M5.** The Transmission Operator shall have evidence of a documented voltage or Reactive Power Schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

- R6.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- M6.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to 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 a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures 1 through 6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

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	Operational Planning	High	N/A	N/A	N/A	The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).
R2	Real-time Operations, Same-day Operations, and Operational Planning	High	N/A	N/A	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.	The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.
R3	Real-time Operations, Same-day Operations, and Operational Planning	High	N/A	N/A	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.	The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R4	Operations Planning	Lower	N/A	N/A	The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.	The Transmission Operator does not have exemption criteria.
R5	Operations Planning	Medium	N/A	The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.	The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to all Generator Operators.	<p>The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators.</p> <p>Or</p> <p>The Transmission Operator does not provide the Generator Operator with the notification requirements for deviations from the</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).
R6	Operations Planning	Lower	The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.	N/A	N/A	The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.

D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

- E.A.13** Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- A voltage set point with a voltage tolerance band and a specified period.
 - An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
 - A voltage band for a specified period.
- E.A.14** Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- The generator terminals.
 - The high side of the generator step-up transformer.
 - The point of interconnection.
 - A location designated by mutual agreement between the Transmission Operator and Generator Operator.
- E.A.15** Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]*
- E.A.16** Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*
- E.A.17** Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators (AVR) to manage MVar loading: [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]

E.A.18.1. Each control loop's design incorporates the AVR's automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures¹

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

¹ The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.

Violation Severity Levels

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.13	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.	For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.
E.A.14	The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.	The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.	The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.
E.A.15	The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of	The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
	than 25% of the voltage schedules.	less than 50% of the voltage schedules.	the voltage schedules.	
E.A.16	The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.	The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.	The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.
E.A.17	The Transmission Operator provided its data to support development of the voltage set point conversion methodology than 30 days but less than or equal to 60 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator Operator.	The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator Operator.	The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.

E #	Lower VSL	Moderate VSL	High VSL	Severe VSL
E.A.18	N/A	The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.	The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on "established limits" and "sufficient reactive resources", and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific area's needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP's criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

Rationale for R5:

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a "tolerance band" as specified in the voltage schedule and the control dead-band in the generator's excitation system.

Voltage Schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator's facility during normal operations, and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator's automatic voltage regulator's control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R6:

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
1	August 2, 2006	BOT Adoption	Revised
1	June 18, 2007	FERC approved Version 1 of the standard.	Revised
1	July 3, 2007	Added "Generator Owners" and "Generator Operators" to Applicability section.	Errata
1	August 23, 2007	Removed "Generator Owners" and "Generator Operators" to Applicability section.	Errata
2	August 5, 2010	Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.	Revised
2	January, 10 2011	FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.	Revised
3	May 9, 2012	Adopted by NERC Board of Trustees; Modified to add a WECC region variance	Revised
3	June 20, 2013	FERC issued order approving VAR-001-3	Revised
3	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	Revised
4	February 6, 2014	Adopted by NERC Board of Trustees	Revised
4	August 1, 2014	FERC issued letter order issued approving VAR-001-4	

Standard VAR-001-4 — Voltage and Reactive Control

Appendix QC-VAR-001-4

Provisions specific to the standard VAR-001-4 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:** Voltage Reactive Control
2. **Number:** VAR-001-4
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 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

Standard VAR-001-4 — Voltage and Reactive Control

Appendix QC-VAR-001-4

Provisions specific to the standard VAR-001-4 applicable in Québec

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

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New

A. Introduction

1. **Title:** Generator Operation for Maintaining Network Voltage Schedules
2. **Number:** VAR-002-3
3. **Purpose:** To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.
4. **Applicability:**
 - 4.1. Generator Operator
 - 4.2. Generator Owner
5. **Effective Dates**

The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, VAR-002-3 shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

- R1.** The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator is exempted by the Transmission Operator, or 2) the Generator Operator has notified the Transmission Operator of one of the following: *[Violation Risk Factor: Medium]* *[Time Horizon: Real-time Operations]*
- That the generator is being operated in start-up,¹ shutdown,² or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
 - That the generator is not being operated in automatic voltage control mode or in the control mode that was instructed by the Transmission Operator for a reason other than start-up, shutdown, or testing.
- M1.** The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).
- R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule³ (within each generating Facility's capabilities⁴) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium]* *[Time Horizon: Real-time Operations]*
- 2.1.** When a generator's AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive

¹ Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

² Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.

³ The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

⁴ Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, reactive power capability may change based on stability considerations.

output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

- 2.2.** When instructed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.
- 2.3.** Generator Operators that do not monitor the voltage at the location specified in their voltage schedule shall have a methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

M2. In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator shall have evidence to show that the generator maintained the voltage or Reactive Power schedule provided by the Transmission Operator, or shall have evidence of meeting the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. Evidence may include, but is not limited to, operator logs, SCADA data, phone logs, and any other notifications that would alert the Transmission Operator or otherwise demonstrate that the Generator Operator complied with the Transmission Operator's instructions for addressing deviations from the voltage or Reactive Power schedule.

For Part 2.1, when a generator's AVR is out of service or the generator does not have an AVR, a Generator Operator shall have evidence to show an alternative method was used to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

For Part 2.2, the Generator Operator shall have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation to the Transmission Operator of why the Generator Operator was unable to comply with the instruction. Evidence may include, but is not limited to, operator logs, SCADA data, and phone logs.

For Part 2.3, for Generator Operators that do not monitor the voltage at the location specified on the voltage schedule, the Generator Operator shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

- R3.** Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time Operations*]
- M3.** The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.
- R4.** Each Generator Operator shall notify its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability due to factors other than a status change described in Requirement R3. If the capability has been restored within 30 minutes of the

Generator Operator becoming aware of such change, then the Generator Operator is not required to notify the Transmission Operator of the change in reactive capability. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

- M4.** The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of becoming aware of a change in reactive capability in accordance with Requirement R4. If the capability has been restored within the first 30 minutes, no notification is necessary.
- R5.** The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*
 - 5.1.** For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
 - 5.1.1.** Tap settings.
 - 5.1.2.** Available fixed tap ranges.
 - 5.1.3.** Impedance data.
- M5.** The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.
- R6.** After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]*
 - 6.1.** If the Generator Owner cannot comply with the Transmission Operator's specifications, the Generator Owner shall notify the Transmission Operator and shall provide the technical justification.
- M6.** The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The Generator Owner shall have evidence that it notified its associated Transmission Operator when it could not comply with the Transmission Operator's step-up transformer tap specifications in accordance with Requirement R6, Part 6.1.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

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	Real-time Operations	Medium	N/A	N/A	N/A	Unless exempted, the Generator Operator did not operate each generator connected to the interconnected transmission system in the automatic voltage control mode or in a different control mode as instructed by the Transmission Operator, and failed to provide the required notifications to Transmission Operator as identified in Requirement R1.
R2	Real-time Operations	Medium	N/A	N/A	The Generator Operator did not have a conversion methodology when it monitors voltage at a location different from the schedule provided by the Transmission Operator.	<p>The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator.</p> <p>OR</p> <p>The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage.</p> <p>OR</p> <p>The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any</p>

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						explanation.
R3	Real-time Operations	Medium	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of the status change.
R4	Real-time Operations	Medium	N/A	N/A	N/A	The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.
R5	Real-time Operations	Lower	N/A	N/A	The Generator Owner failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.	The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
R6	Real-time Operations	Lower	N/A	N/A	N/A	The Generator Owner did not ensure the tap changes were made according the Transmission Operator’s specifications. OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	5/1/2006	Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.	July 5, 2006
1a	12/19/2007	Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007	Revised
1a	1/16/2007	In Section A.2., Added “a” to end of standard number. Section F: added “1.”; and added date.	Errata
1.1a	10/29/2008	BOT adopted errata changes; updated version number to “1.1a”	Errata
1.1b	3/3/2009	Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009	Revised
2b	8/16/2012	Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b. Adopted by Board of Trustees.	Revised
2b	4/16/2013	FERC Order issued approving VAR-002-2b	
3	5/6/2014	Adopted by the NERC Board of Trustees	
3	8/1/2014	FERC issued letter order approving VAR-002-3	

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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 has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

Rationale for R2:

Requirement R2 details how a Generator Operator (GOP) operates its generator(s) to provide voltage support and when the GOP is expected to notify the Transmission Operator (TOP). In an effort to remove prescriptive notification requirements for the entire continent, the VAR-002-3 standard drafting team (SDT) opted to allow each TOP to determine the notification requirements for each of its respective GOPs based on system requirements. Additionally, a new Part 2.3 has been added to detail that each GOP may monitor voltage by using its existing facility equipment.

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

Voltage Schedule Tolerances: The bandwidth that accompanies the voltage target in a voltage schedule should reflect the anticipated fluctuation in voltage at the GOP's Facility during normal operations and be based on the TOP's assessment of N-1 and credible N-2 system contingencies. The voltage schedule's bandwidth should not be confused with the control dead-band that is programmed into a GOP's AVR control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule's bandwidth.

Rationale for R3:

This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

Rationale for R4:

This requirement has been bifurcated from the prior version VAR-002-2b Requirement R3. This requirement allows GOPs to report reactive capability changes after they are made aware of the change. The current standard requires notification as soon as the change occurs, but many GOPs are not aware of a reactive capability change until it has taken place.

Rationale for R5:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected. The prior version of VAR-002-2b, Requirement R4.1.4 (the +/- voltage range with step-change in % for load-tap changing transformers) has been removed. The percentage information was not needed because the tap settings, ranges and impedance are required. Those inputs can be used to calculate the step-change percentage if needed.

Rationale for R6:

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.

Standard VAR-002-3 — Generator Operation for Maintaining Network Voltage Control

Appendix QC-VAR-002-3

Provisions specific to the standard VAR-002-3 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:** Generator Operation for Maintaining Network Voltage Control
2. **Number:** VAR-002-3
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 and Measures

Specific provisions applicable to requirement R2:

- For Generator Operators that are not Transmission Owners:

Unless exempted by the Transmission Operator, each Generator Operator shall maintain the voltage or reactive power (in accordance with Facility Ratings), at the output of its generating facilities in order to maintain the voltage of the Main Transmission System within prescribed ranges, as directed by the Transmission Operator.
- For Generator Operators that are also Transmission Owners:

Unless exempted by the Transmission Operator, each Generator Operator that is also a Transmission Owner shall maintain the voltage or reactive power (in accordance with Facility Ratings), at the connection points of its network with that of a third party in order to maintain the voltage of the Main Transmission System within prescribed ranges, as directed by the Transmission Operator.

Specific provision applicable to requirements R5 and R6:

Standard VAR-002-3 — Generator Operation for Maintaining Network Voltage Control

Appendix QC-VAR-002-3

Provisions specific to the standard VAR-002-3 applicable in Québec

- Generator Operators are not required to meet requirements R5, R5.1, R5.1.1, R5.1.2, R5.1.3, R6 and R6.1 considering that the Transmission Operator will give instructions based on the voltage to maintain on the transmission system.

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

Guidelines and Technical Basis

No specific provision

Revision History

Revision	Adoption Date	Action	Change Tracking
0	Xx month 201x	New appendix	New