NORMES DE FIABILITÉ DE LA NERC

(VERSION ANGLAISE)

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 federal[1], 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 federal[2], 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] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

[2] *Id.*

of sight[3] 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 below[4] [*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 Outage[7],
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 below[9] [*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 Outage[13]

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 ROW[14] [*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*]:

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[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 Owner[15]
- 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			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.	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: • 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			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.	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: • 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
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.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
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.

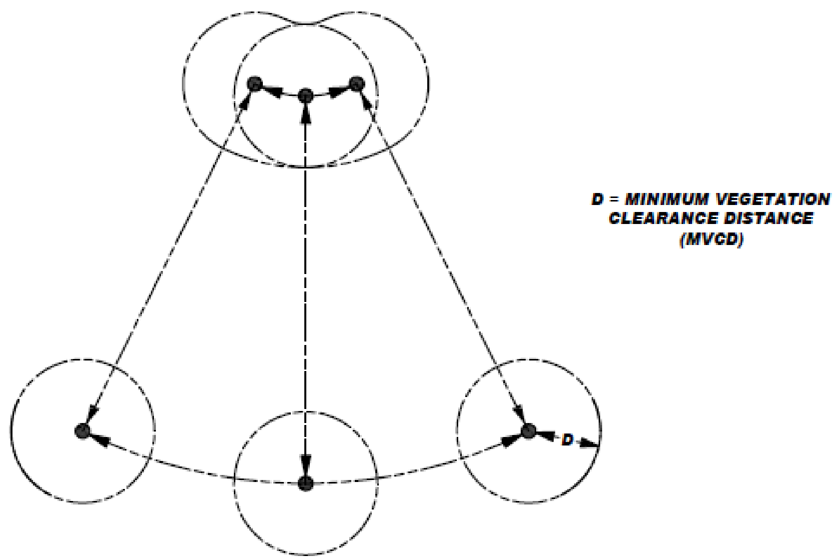


Figure 1

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 Over sea level up to 500 ft (Over sea level up to 152.4 m)	MVCD meters Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	MVCD meters Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	MVCD meters Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	MVCD meters Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	MVCD meters Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	MVCD meters Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	MVCD meters Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	MVCD meters Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	MVCD meters Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	MVCD meters Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	MVCD meters 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	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	

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).

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

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.

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

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.

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.*

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]*

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.*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

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

For each Protection System 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:

Requirement Number	Lower VSL	Moderate VSL	High VSL	Severe VSL
				• 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.

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	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

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: • Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • 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: • 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: • 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: • 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: • 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: • Station dc supply voltage Inspect: • Electrolyte level • For unintentional grounds
	18 Calendar Months	Verify: • Float voltage of battery charger • Battery continuity • Battery terminal connection resistance • Battery intercell or unit-to-unit connection resistance Inspect: • 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>
<tr><th colspan="3">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)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="4">Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• For unintentional grounds</td></tr>
<tr><td>6 Calendar Months</td><td>Inspect:
• Condition of all individual units by measuring battery cell/unit internal ohmic values.</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
• Float voltage of battery charger
• Battery continuity
• Battery terminal connection resistance
• Battery intercell or unit-to-unit connection resistance
Inspect:
• Physical condition of battery rack</td></tr>
<tr><td>6 Calendar Months
-or-
3 Calendar Years</td><td>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.</td></tr>
</table>

<table>
<tr><th colspan="3">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)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Protection System Station dc supply Nickel-Cadmium (NiCad) batteries not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
Station dc supply voltage
Inspect:
Electrolyte level
For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Verify:
Float voltage of battery charger
Battery continuity
Battery terminal connection resistance
Battery intercell or unit-to-unit connection resistance
Inspect:
Cell condition of all individual battery cells.
Physical condition of battery rack</td></tr>
<tr><td>6 Calendar Years</td><td>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank.</td></tr>
</table>

<table>
<tr><th colspan="3">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)).</th></tr>
<tr><th>Component Attributes</th><th>Maximum Maintenance Interval</th><th>Maintenance Activities</th></tr>
<tr><td rowspan="3">Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f).</td><td>4 Calendar Months</td><td>Verify:
• Station dc supply voltage
Inspect:
• For unintentional grounds</td></tr>
<tr><td>18 Calendar Months</td><td>Inspect:
Condition of non-battery based dc supply</td></tr>
<tr><td>6 Calendar Years</td><td>Verify that the dc supply can perform as manufactured when ac power is not present.</td></tr>
</table>

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.

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	Verify that settings are as specified For non-microprocessor relays: • Test and, if necessary calibrate For microprocessor relays: • 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: • 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: • 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
Monitored microprocessor protective relay with preceding row attributes and the following: • 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 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:

> **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.*

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.

> **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.

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.

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. Functional Entities

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. Special Protection System are those classified type I or II by NPCC.

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

Appendix QC-PRC-005-2
Provisions specific to the standard PRC-005-2 applicable in Québec

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

Replace all occurrences of the expression "Non-BES" with the expression "Non-BPS"

Table 2

No specific provision

Table 3

Replace all occurrences of the expression "Non-BES" with the expression "Non-BPS"

Attachment A

No specific provision

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

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-service[1] 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.

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-service[2] 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.

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

	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.

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

$$C = V^2_g/2*(1/X_s-1/X_d)$$

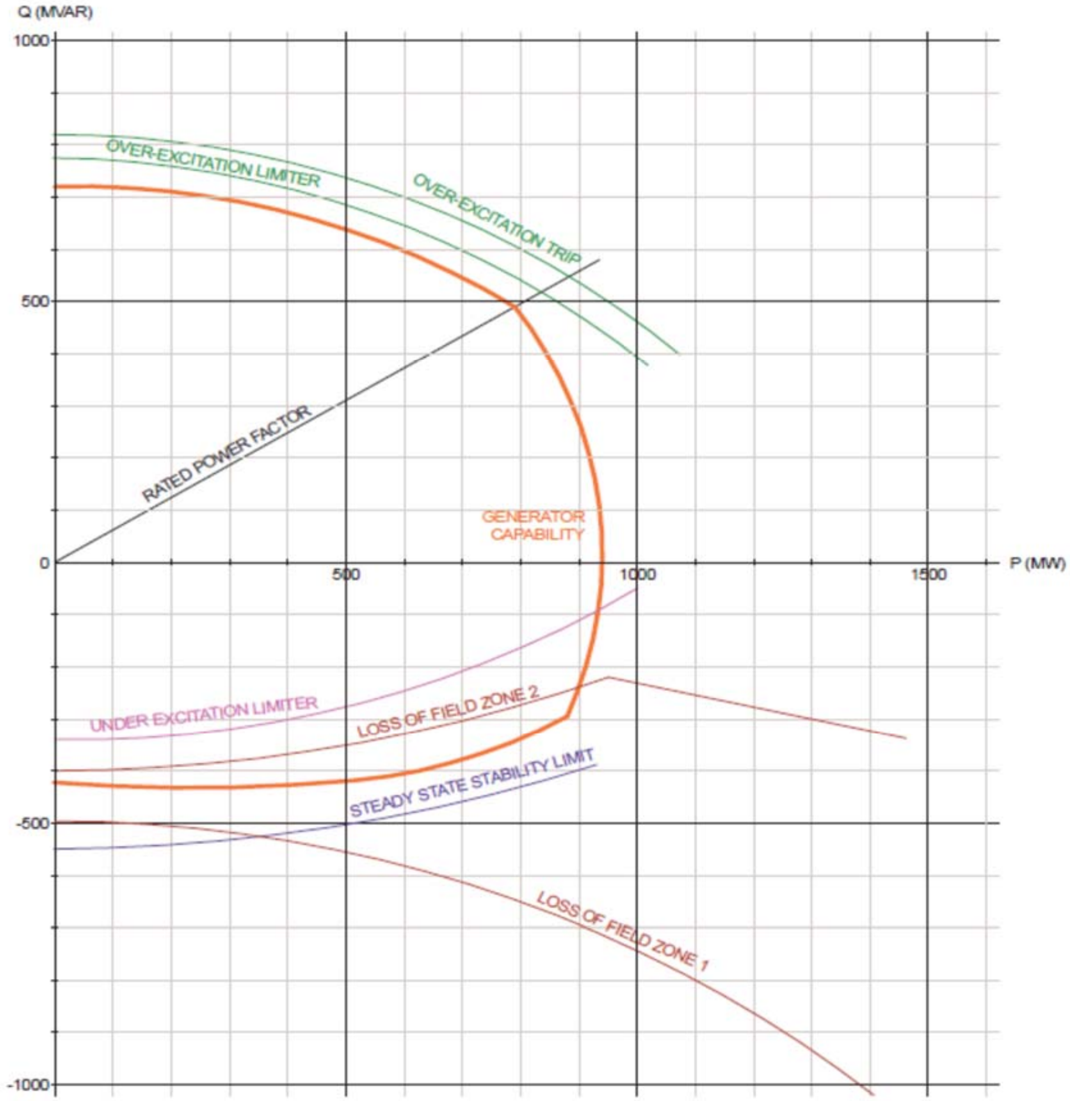
$$R = V^2_g/2*(1/X_s+1/X_d)$$

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:

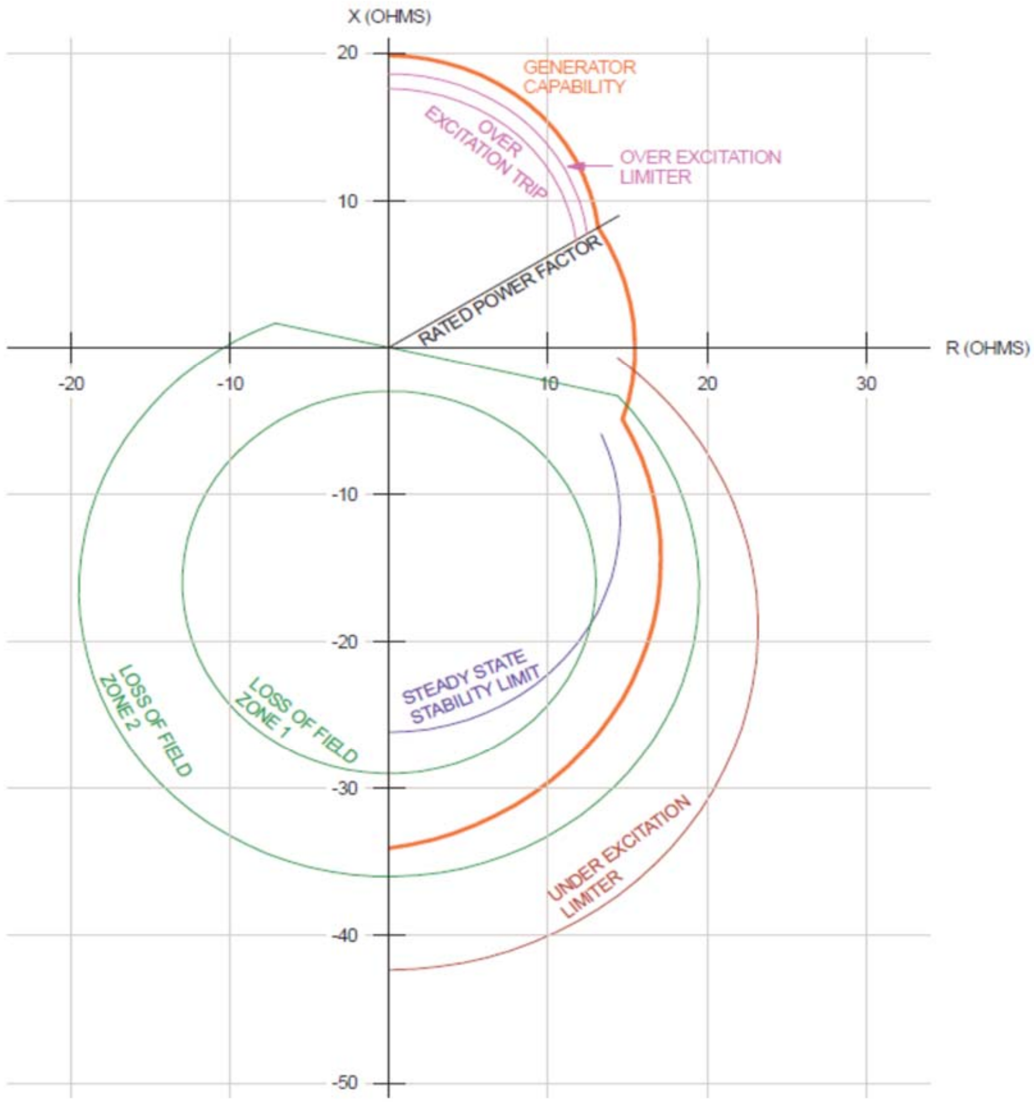
$$C = (X_d-X_s)/2$$

$$R = (X_d+X_s)/2$$

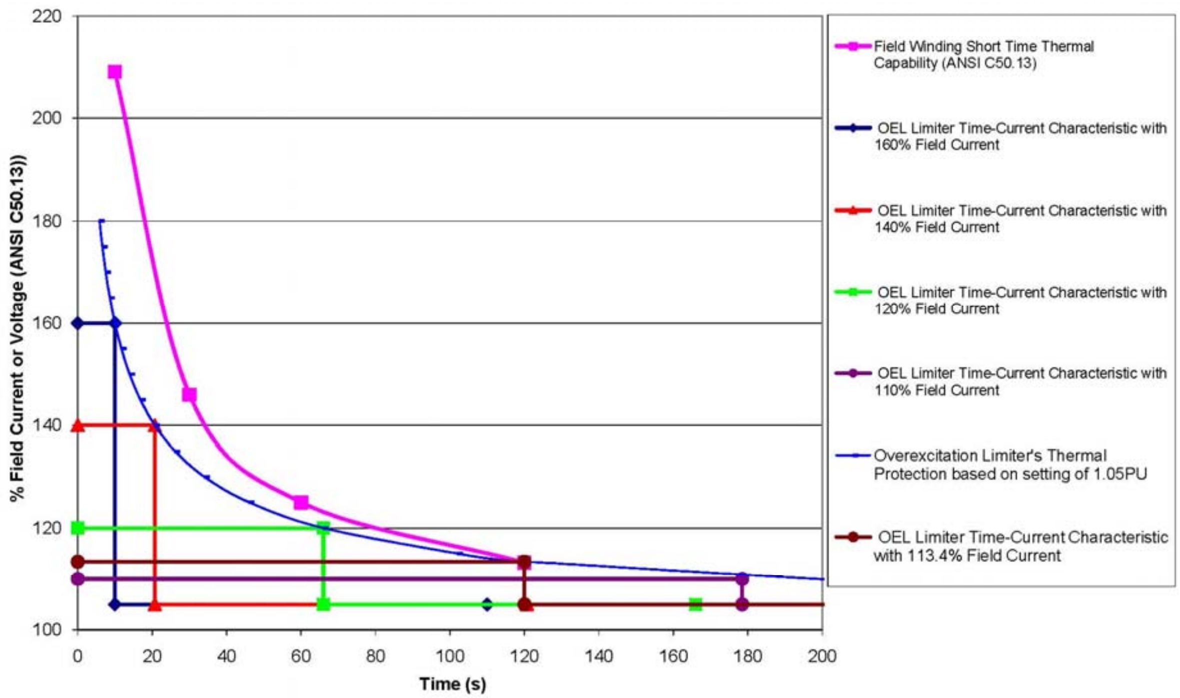
Section G Attachment 1 – Example of Capabilities, Limiters and Protection on a P-Q Diagram at nominal voltage and frequency



Section G Attachment 2 – Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency



Section G Attachment 3 - Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot



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

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

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 Rating[1] 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 capability[2].

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 temperature[3].

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.

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[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	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. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	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.
R3	N/A	N/A	N/A	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.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR 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. OR 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.	months or more lapsed between assessments. OR 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)	OR 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. OR 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) OR 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

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		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) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

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 analyses[4] 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

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.

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:

4.2.1 Circuits Subject to Requirements R1-R5:

4.2.1.1 Transmission lines operated at 200kV and above, except Elements that connect GSU transformers(s) to the Transmission system that are used exclusively to export energy directly from a Main Transmission System (RTP) generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 No specific provisions

4.2.1.3 Transmission lines operated below 100 kV that are part of the RTP and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.4 No specific provision

4.2.1.5 No specific provision

4.2.1.6 Transformers with low voltage terminals connected below 100kV that are part of the RTP 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 100kV to 200kV and transformers with low voltage terminals connected at 100kV to 200kV, except Elements that connected 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.

4.2.2.2 Transmission lines operated below 100kV and transformers with low voltage terminals connected below 100kV that are part of the RTP, except Elements that connect the GSU transformer(s) to the Transmission system that are exclusively to export energy directly from a RTP generating unit or generating plant. Elements may also supply generating plant loads.

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. 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 setting from limiting transmission system loadability while maintaining reliable protection of the RTP for all fault conditions. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Specific provision applicable to criterion 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:

- No specific provision
- 115% of the highest operator established emergency transformer rating or 100% of the highest rating established during the long term emergency condition when one or more transformers are failed

10.1 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 Data Retention

No specific provision

1.3 Compliance Monitoring and Assessment Process

No specific provision

1.4 Additional Compliance Information

No specific provision

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/At	N/A	N/A	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 RTP for all faults conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power angle of 30 degrees.
R2	No specific provision			
R3	No specific provision			
R4	No specific provision			
R5	No specific provision			
R6	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 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 *PRC-025-1 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

NERC System Protection and Control Subcommittee, July 2010, "Power Plant and Transmission System Protection Coordination."

IEEE C37.102-2006, "Guide for AC Generator Protection."

PRC-025-1 – 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 If the relay is installed on the generator-side of the GSU transformer use Option 7	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		
		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 If the relay is installed on the generator-side of the GSU transformer use Option 9	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 If the relay is installed on the generator-side of the GSU transformer use Option 10	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)
	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 asynchronous generators only (including inverter-based installations)	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 11	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)
	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 asynchronous generators only (including inverter-based installations)	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 If the relay is installed on the generator-side of the GSU transformer use Option 12	19	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Rationale:

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

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New

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.

   3.3. Exemptions: The generating facilities that are not connected to the RTP are exempted from the application of this standard.

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.

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