Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

Draft 3 of PRC-024-4 is posted for final ballot. Non-substantive corrections were identified during the last additional ballot. This draft includes those corrections.

Completed Actions	Date
Standards Committee accepted revised Standard Authorization Request (SAR) for posting	April 19, 2023
Standards Committee approved waivers to the Standards Process Manual	December 13, 2023
25-day formal comment period with initial ballot	March 27 - April 22, 2024
15-day formal comment period and additional ballot	June 18 – July 8, 2024

Anticipated Actions	Date
Final ballot	September 25 – September 30, 2024
Board Adoption	October 8, 2024

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title:** **Frequency and Voltage Protection Settings for Synchronous Generators, Type 1 and Type 2 Wind Resources, and Synchronous Condensers**

2. **Number:** **PRC-024-4**

3. **Purpose:** To assure that protection of synchronous generators, type 1 and type 2 wind resources, and synchronous condensers do not cause tripping during defined frequency and voltage excursions in support of the Bulk Power System (BPS).

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Generator Owners that apply protection listed in Sections 4.2.1 or 4.2.2.

4.1.2. Transmission Owners that apply protection listed in Section 4.2.2.

4.1.3. Transmission Owners (in the Quebec Interconnection only) that own a BES generator step-up (GSU) transformer or main power transformer (MPT)[1] and apply protection listed in Section 4.2.1.

4.1.4. Planning Coordinators (in the Quebec Interconnection only)

4.2. Facilities[2]:

4.2.1 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the generating resource(s); or (ii) provide signals to the generating resource(s) to trip; and are applied to the following:

4.2.1.1 Bulk Electric System (BES) synchronous generators.

4.2.1.2 BES GSU transformer(s) for synchronous generators.

4.2.1.3 High-side of the synchronous generator-connected unit auxiliary transformer[3] (UAT) installed on BES generating resource(s).

4.2.1.4 Individual dispersed power producing type 1 or type 2 wind resource(s) identified in the BES Definition, Inclusion I4.

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[1] For the purpose of this standard, the MPT is the power transformer that steps up voltage from multiple small synchronous generators (e.g. multiple small hydro generators connecting to a common bus) or from a type 1 or type 2 wind resource collector station to transmission voltage .

[2] It is not required to install or activate the protections described in Facilities Section 4.2.

[3] These transformers are variously referred to as station power UAT, or station service transformer(s) used to provide overall auxiliary power to the synchronous generators. This UAT is the transformer connected on the generator bus between the low side of the GSU and the generator terminal.

4.2.1.5 Elements that are designed primarily for the delivery of capacity from multiple synchronous generators connecting to a common bus or individual dispersed power producing type 1 or type 2 wind resources identified in the BES Definition, Inclusion I4, to the point where those resources aggregate to greater than 75 MVA.

4.2.1.6 MPT of multiple synchronous generators connecting to a common bus or MPT of individual dispersed power producing type 1 or type 2 wind resources as identified in the BES Definition, Inclusion I4.

4.2.2 Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip transmission connected synchronous condensers; or (ii) provide signals to trip transmission connected synchronous condenser and are applied to the following:

4.2.2.1 BES synchronous condensers

4.2.2.2 BES step-up transformer(s) for synchronous condensers.

4.2.2.3 High-side of the synchronous condenser-connected unit auxiliary transformer (UAT).

4.2.3 **Exemptions:** Protection on all auxiliary equipment within the synchronous generator, type 1 or type 2 wind resource, or synchronous condenser Facility.

5. **Effective Date:** See Implementation Plan for PRC-024-4

B. Requirements and Measures

R1. Each Generator Owner and Transmission Owner shall set applicable frequency protection[4] in accordance with PRC-024-4 Attachment 1 such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a frequency excursion with the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Applicable frequency protection may be set to trip within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M1. Each Generator Owner and Transmission Owner shall have evidence that the applicable frequency protection has been set in accordance with Requirement R1, such as dated setting sheets, calibration sheets, calculations, or other documentation.

R2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[5] in accordance with PRC-024-4 Attachment 2, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024-4 Attachment 2, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

M2. Each Generator Owner and Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

R3. Each Generator Owner and Transmission Owner shall document each known regulatory or equipment limitation[6] that prevents its Facility, with applicable frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2, including (but not limited to) study results, experience from an actual event, or manufacturer's advice. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

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[4] Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

[5] Ibid.

[6] Excludes limitations caused by the setting capability of the frequency, voltage, and volts per hertz protective relays applied to the synchronous generator(s), type 1 and type 2 wind resource(s), and synchronous condenser(s). This does not exclude limitations originating in the equipment protected by the relay(s).

3.1. The Generator Owner and Transmission Owner shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days of any of the following:

- Identification of a regulatory or equipment limitation.
- Repair of the equipment causing the limitation that removes the limitation.
- Replacement of the equipment causing the limitation with equipment that removes the limitation.
- Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.

M3. Each Generator Owner and Transmission Owner shall have evidence that it has documented and communicated any known regulatory or equipment limitations that resulted in an exception to Requirements R1 or R2 in accordance with Requirement R3, such as a dated email or letter that contains such documentation as study results, experience from an actual event, or manufacturer's advice.

R4. Each Generator Owner and Transmission Owner shall provide its applicable protection settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner that models the associated Facility within 60 calendar days of receipt of a written request for the data and within 60 calendar days of any change to those previously requested settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of protection setting changes is not required. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Generator Owner and Transmission Owner shall have evidence that it communicated applicable protection settings in accordance with Requirement R4, such as dated emails, correspondence or other evidence and copies of any requests it has received for that information.

C. Compliance

1. **Compliance Monitoring Process**

    1.1. Compliance Enforcement Authority: “Compliance Enforcement Authority” means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

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

    - The Generator Owner and Transmission Owner shall keep data or evidence of Requirements R1 through R4 for five years or until the next audit, whichever is longer.
    - If a Generator Owner or Transmission Owner is found non-compliant, the Generator Owner or Transmission Owner shall keep information related to the non-compliance until mitigation is complete and approved for the time period specified above, whichever is longer.

    1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable frequency protection so that it does not trip according to Requirement R1.
R2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable voltage protection so that it does not trip according to Requirement R2.
R3.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 30 calendar days but less than or equal to 60 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 60 calendar days but less than or equal to 90 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner documented the known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2 and communicated the documented limitation to its Planning Coordinator and Transmission Planner more than 90 calendar days but less than or equal to 120 calendar days of identifying the limitation.	The Generator Owner or Transmission Owner failed to document any known non-protection system equipment limitation that prevented it from meeting the criteria in Requirement R1 or R2. OR The Generator Owner or Transmission Owner failed to communicate the documented limitation to its Planning Coordinator and Transmission Planner within 120 calendar

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				days of identifying the limitation.
R4.	The Generator Owner or Transmission Owner provided its protection settings more than 60 calendar days but less than or equal to 90 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 60 calendar days but less than or equal to 90 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 90 calendar days but less than or equal to 120 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner provided protection settings more than 90 calendar days but less than or equal to 120 calendar days of a written request.	The Generator Owner or Transmission Owner provided its protection settings more than 120 calendar days but less than or equal to 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner or provided protection settings more than 120 calendar days but less than or equal to 150 calendar days of a written request.	The Generator Owner or Transmission Owner failed to provide its protection settings within 150 calendar days of any change to those settings. OR The Generator Owner or Transmission Owner failed to provide protection settings within 150 calendar days of a written request.

D. Regional Variances

D.A. Variance for the Quebec Interconnection

This Variance replaces Requirement R2 of the continent-wide standard in its entirety and adds a new requirement, Requirement D.A.5., applicable to Planning Coordinators in the Quebec Interconnection.

This Variance replaces continent-wide Requirement R2 in its entirety with the following:

D.A.2. Each Generator Owner and Transmission Owner shall set applicable voltage protection[7] in accordance with PRC-024 Attachment 2A, such that the applicable protection does not cause the Facility to which it is applied to trip within the "no trip zone" during a voltage excursion at the high-side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- For newly designated strategic power plants, applicable protections must comply with the high voltage durations for such plants within 48 calendar months of the notification made pursuant to Requirement D.A.5. During this transition period, voltage protections must at least comply with the high voltage durations for "all power plants".
- Applicable voltage protection may be set to trip during a voltage excursion within a portion of the "no trip zone" of PRC-024 Attachment 2A for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.
- If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2A, then the Generator Owner or Transmission Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.

M.D.A.2. Each Generator Owner and Transmission Owner shall have evidence that applicable voltage protection has been set in accordance with Requirement R2, such as dated setting sheets, voltage-time boundaries, calibration sheets, coordination plots, dynamic simulation studies, calculations, or other documentation.

This Variance adds the following Requirement:

D.A.5 Each Planning Coordinator shall designate, at least once every five calendar years, the strategic power plants that must comply with Attachment 2A and notify, within 30 calendar days of its designation,

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[7] Frequency, voltage, and volts per hertz protection (whether provided by relaying or functions within associated control systems) that respond to electrical signals and: (i) directly trip the synchronous generator(s), type 1 or type 2 wind resource(s), or synchronous condenser(s); or (ii) provide signals to trip the same Facilities.

each Generator Owner or Transmission Owner that owns facilities[8] in the strategic power plants. *[Violation Risk Factor: Medium] [Time Horizon: Long-term planning]*

M.D.A.5 Each Planning Coordinator shall have evidence that it designated, at least once every five calendar years, strategic power plants in accordance with Requirement D.A.5, Part 5 and shall have dated evidence that each Generator Owner or Transmission Owner has been notified in accordance with Requirement D.A.5, part 5.2. Evidence may include, but is not limited to letters, emails, electronic files, or hard copy records demonstrating transmittal of information.

[8] Facilities in the strategic power plants include facilities with synchronous generator(s) from the generator up to and including the MPT or GSU.

Violation Severity Levels

This Variance adds a VSL for D.A.5 and modifies the VSL for R2 as follows:

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
D.A.2.	N/A	N/A	N/A	The Generator Owner or Transmission Owner failed to set its applicable voltage protection so that it does not trip in accordance with Requirement D.A.2. OR The Generator Owner or Transmission Owner set its applicable voltage protection in accordance with Requirement D.A.2 but, for strategic power plants, failed to do so within 48 months of notification.
D.A.5.	N/A	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 31 days and 45 days after its designation.	The Planning Coordinator designated strategic power plants at least once every five calendar years but notified each Generator Owner or Transmission Owner that owns facilities in the strategic power plants between 46 days and 60 days after its designation.	The Planning Coordinator failed to designate, at least once every five years, the strategic power plants that must comply with Attachment 2A. OR The Planning Coordinator failed to notify, each Generator Owner or Transmission Owner that owns facilities in the strategic power plants or notified them more than 60 days after its designation.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	May 9, 2013	Adopted by the NERC Board of Trustees	
1	March 20, 2014	FERC Order issued approving PRC-024-1. (Order becomes effective on 7/1/16.)	
2	February 12, 2015	Adopted by the NERC Board of Trustees	Standard revised in Project 2014-01: Applicability revised to clarify application of requirements to BES dispersed power producing resources
2	May 29, 2015	FERC Letter Order in Docket No. RD15-3-000 approving PRC-024-2	Modifications to adjust the applicability to owners of dispersed generation resources.
3	February 6, 2020	Adopted by the NERC Board of Trustees	Standard revised in Project 2018-04
3	July 9, 2020	FERC Letter Order approved PRC024-3. Docket No. RD20-7-000	
3	July 17, 2020	Effective Date	10/1/2022
4	August 2, 2024	Revisions made by the 2020-02 Drafting Team	Revision accounts for changes with PRC-029-1 as part of Milestone 2 of NERC’s work plan to address FERC Order No. 901.

Attachment 1

(Frequency No Trip Boundaries by Interconnection[9])

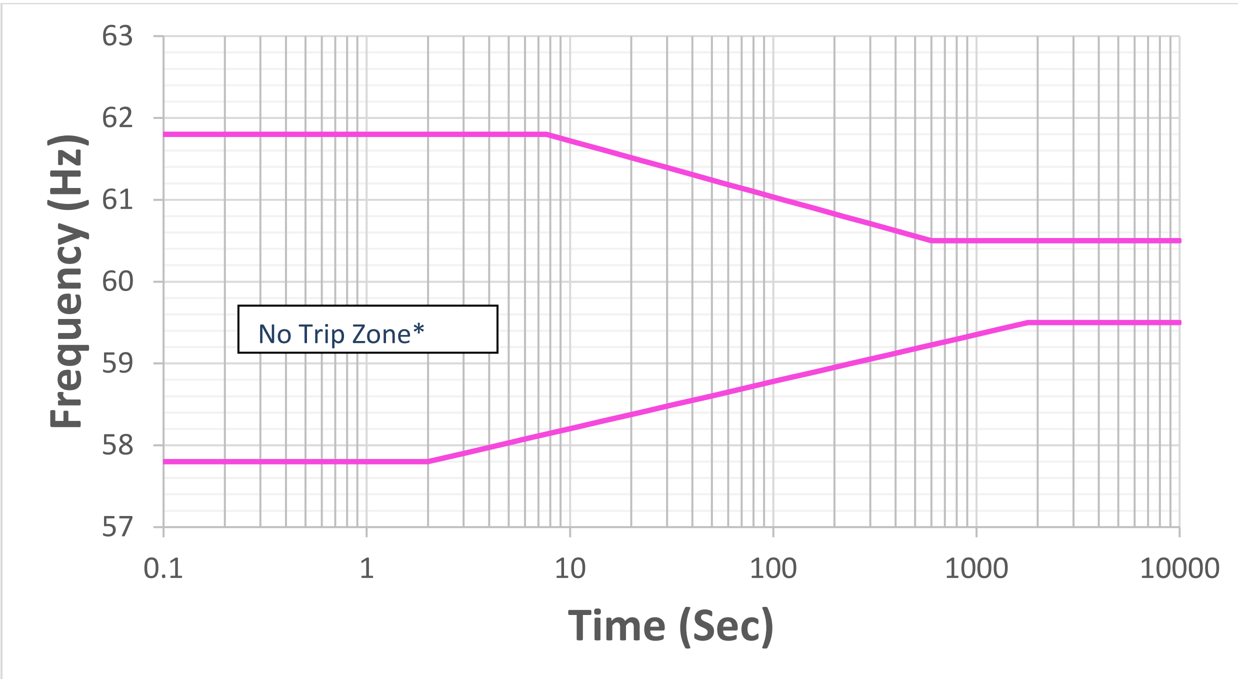

Figure 1: Eastern Interconnection Boundaries

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Table 1: Frequency Boundary Data Points - Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[10]	≤57.8	Instantaneous[11]
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

[9] The figures do not visually represent the “no trip zone” boundaries before 0.1 seconds and after 10,000 seconds. The Frequency Boundary Data Points Table defines the entirety of the “no trip zone” boundaries.

[10] Frequency is calculated over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible.

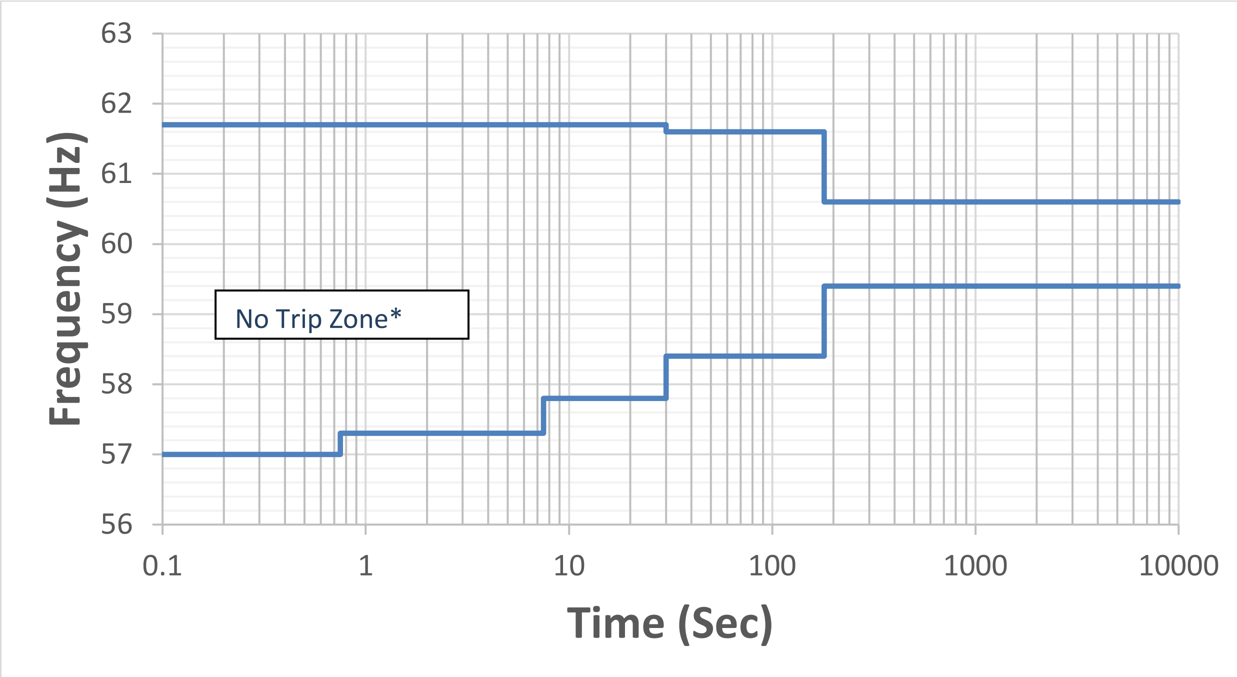

Figure 2: Western Interconnection Boundaries

***** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Table 2: Frequency Boundary Data Points – Western Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.7	Instantaneous[11]	≤57.0	Instantaneous[11]
≥61.6	30	≤57.3	0.75
≥60.6	180	≤57.8	7.5
<60.6	Continuous operation	≤58.4	30
		≤59.4	180
		>59.4	Continuous operation

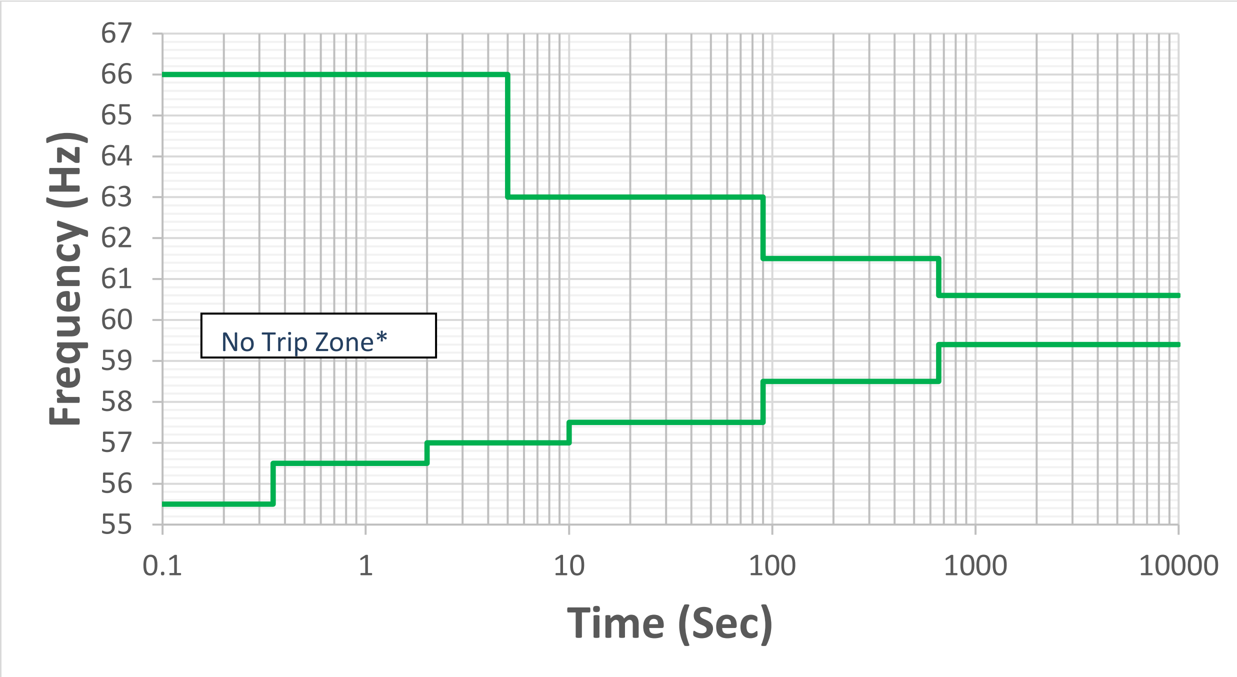

Figure 3: Quebec Interconnection Boundaries

***** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Table 3: Frequency Boundary Data Points – Quebec Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (Sec)**
>66.0	Instantaneous[11]	<55.5	Instantaneous[11]
≥63.0	5	≤56.5	0.35
≥61.5	90	≤57.0	2
≥60.6	660	≤57.5	10
<60.6	Continuous operation	≤58.5	90
		≤59.4	660
		>59.4	Continuous operation

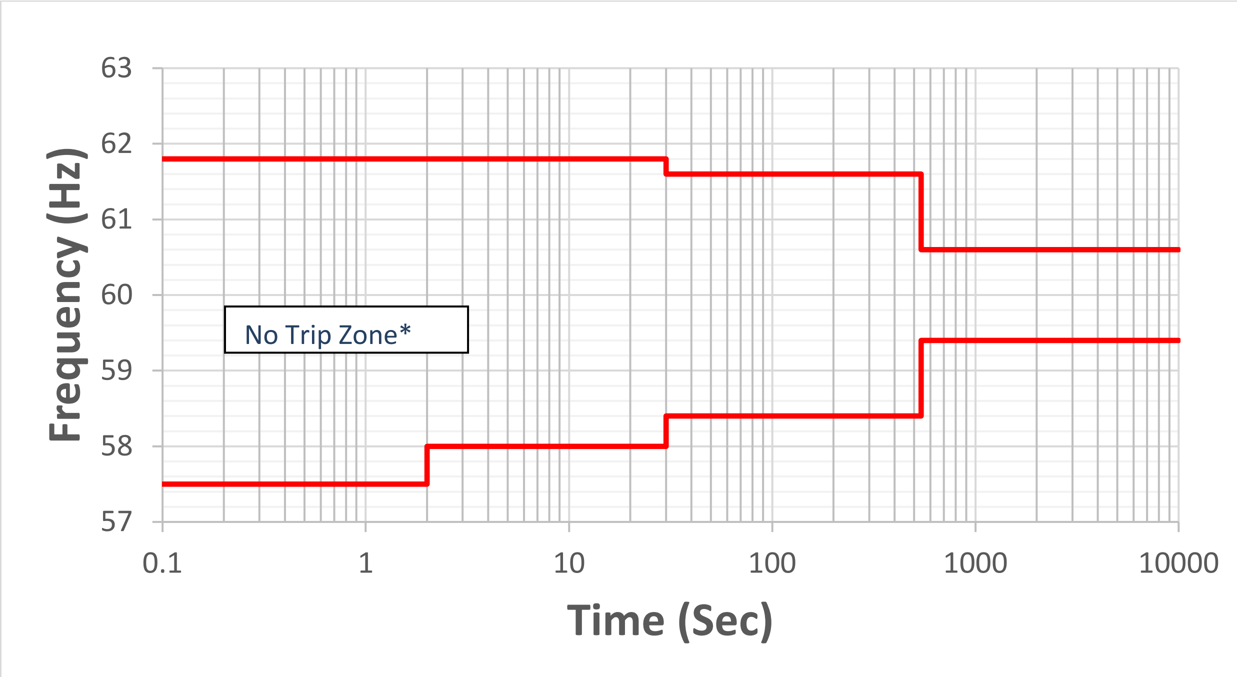

Figure 4: ERCOT Interconnection Boundaries

***** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Table 4: Frequency Boundary Data Points – ERCOT Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	**Minimum Time (Sec)**	**Frequency (Hz)**	**Minimum Time (sec)**
≥61.8	Instantaneous[11]	≤57.5	Instantaneous[11]
≥61.6	30	≤58.0	2
≥60.6	540	≤58.4	30
<60.6	Continuous operation	≤59.4	540
		>59.4	Continuous operation

PRC-024 — Attachment 2

(Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections)

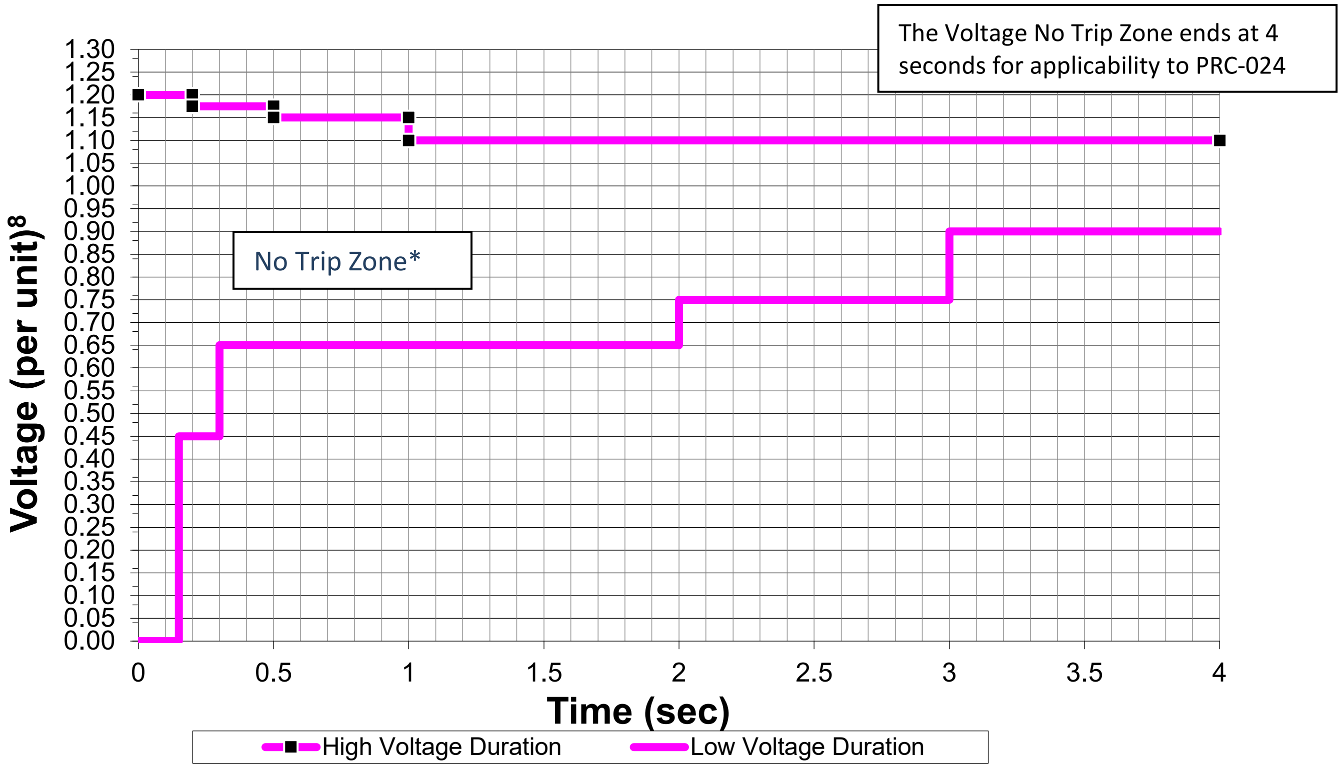

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

** The area outside the "No Trip Zone" is not a "Must Trip Zone."*

Table 5: Voltage Boundary Data Points

High Voltage Duration		Low Voltage Duration	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	Minimum Time (sec)
≥1.200	0.00	<0.45	0.15
≥1.175	0.20	<0.65	0.30
≥1.15	0.50	<0.75	2.00
≥1.10	1.00	<0.90	3.00
<1.10	4.00	≥ 0.90	4.00

Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections

Boundary Details:

1. Unless otherwise specified by the Transmission Planner, the per unit voltage base for these boundaries is the nominal transmission system voltage (e.g., 100 kV, 115 kV, 138 kV, 161 kV, 230 kV, 345 kV, 400 kV, 500 kV, 765 kV, etc.).
2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
3. When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
4. Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase per unit voltage.
5. For applicability to PRC-024, the “no trip zone” ends at 4 seconds.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high-side of the GSU/MPT. For resources with multiple stages of step up to reach interconnecting voltage, this is the high-side of the transformer with a low side below 100kV and a high-side 100kV or above**.** When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high-side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the synchronous generator, type 1 or 2 wind resources, or synchronous condenser under study.
b. All installed wind resource reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals or the collector station and the high-side of the GSU/MPT.
d. For dynamic simulations, the synchronous generator or condenser automatic voltage regulator is in automatic voltage control mode with associated limiters in service.

PRC-024— Attachment 2A

(Voltage No-Trip Boundaries – Quebec Interconnection)

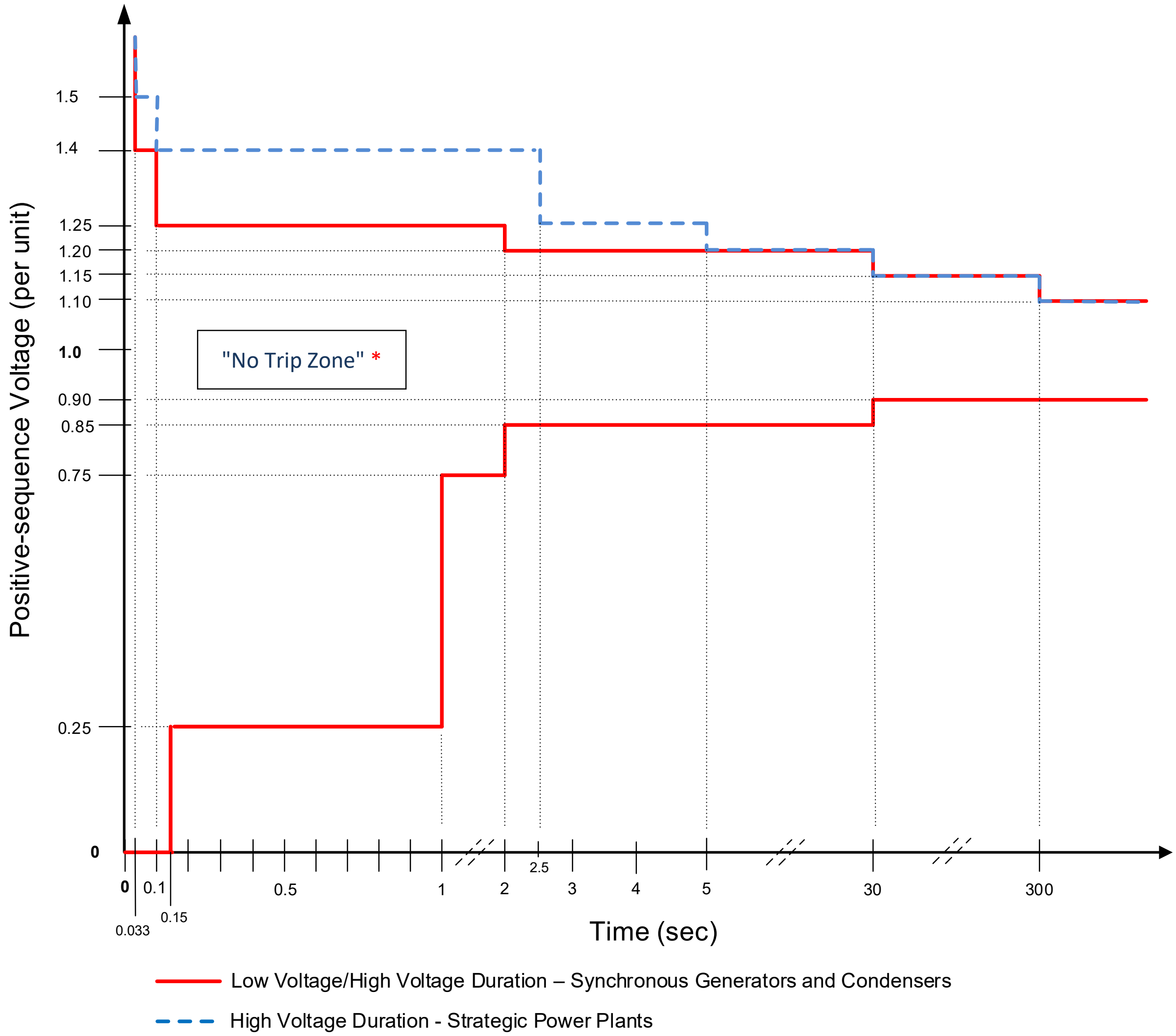

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

**** The area outside the "No Trip Zone" is not a "Must Trip Zone."***

Table 6: High Voltage Boundary Data Points – Quebec Interconnection

High Voltage Duration for all Synchronous Generators and Condensers		High Voltage Duration for strategic Power Plants	
Voltage (per unit)	Minimum Time (sec)	Voltage (per unit)	Minimum Time (sec)
---	---	>1.50	0.033
>1.40	0.033	>1.40	0.10
>1.25	0.10	>1.25	2.50
>1.20	2.00	>1.20	5.00
>1.15	30	>1.15	30
>1.10	300	>1.10	300
≤1.10	continuous	≤1.10	continuous

Table 7: Low Voltage Boundary Data Points – Quebec Interconnection

Low Voltage Duration for all Synchronous Generators and Condensers	
Voltage (per unit)	Minimum Time (sec)
<0.25	0.15
<0.75	1.00
<0.85	2.00
<0.90	30
≥0.90	continuous

Attachment 2A: Voltage Boundary Clarifications – Quebec Interconnection

Boundary Details:

1. The per unit voltage base for these boundaries is the nominal operating voltage (e.g., 120 kV, 161 kV, 230 kV, 315 kV, 735 kV, etc.).
2. The values in the table represent the minimum time durations allowed for specified voltage excursion thresholds.
3. When evaluating volts per hertz protection, either assume a system frequency of 60 Hertz or the magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.
4. Voltages in the Quebec Interconnection boundaries assume positive-sequence values.

Evaluating Protection Settings:

The voltage values in the Attachment 2A voltage boundaries are voltages at the high-side of the GSU/MPT. For resources with multiple stages of step up to reach interconnecting voltage, this is the high-side of the transformer that connects to the interconnecting voltage. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high-side of the GSU/MPT. A steady state calculation or dynamic simulation may be used.

If using a steady state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

a. The most probable real and reactive loading conditions for the unit under study.
b. All installed generating plant reactive support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
c. Account for the actual tap settings of transformers between the generator terminals and the high-side of the GSU/MPT.
d. For dynamic simulations, the automatic voltage regulator is in automatic voltage control mode with associated limiters in service.