Normes de fiabilité

(version anglaise)

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.

[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,

[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.
4	October 8, 2024	Adopted by the NERC Board of Trustees	Standard revised in Project 2020-02

Attachment 1
(Frequency No Trip Boundaries by Interconnection[9])

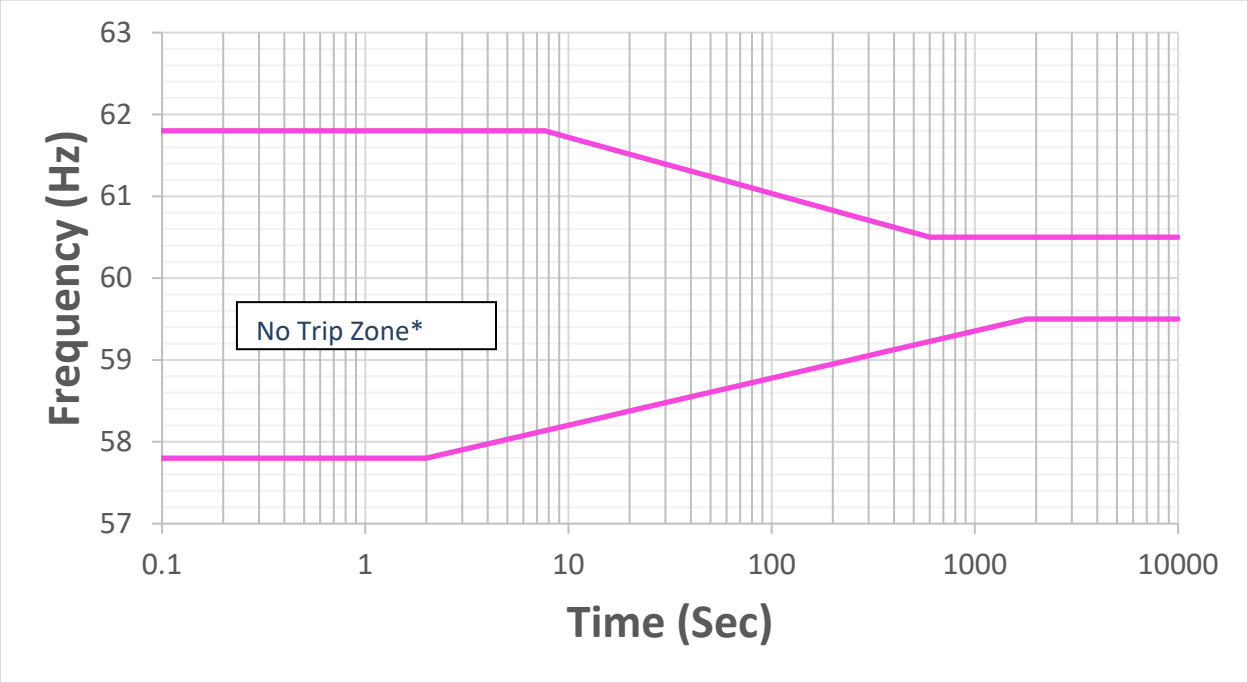

Figure 1: Eastern Interconnection Boundaries

**** 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.

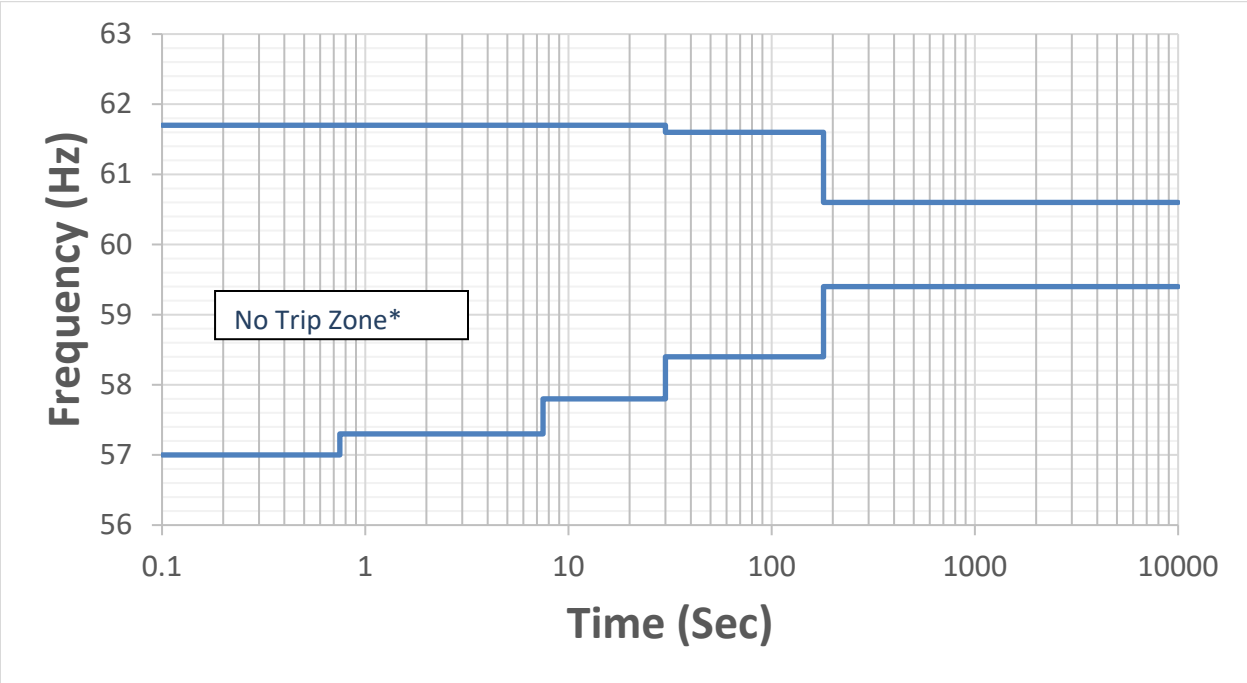

Figure 2: Western Interconnection Boundaries

**** 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

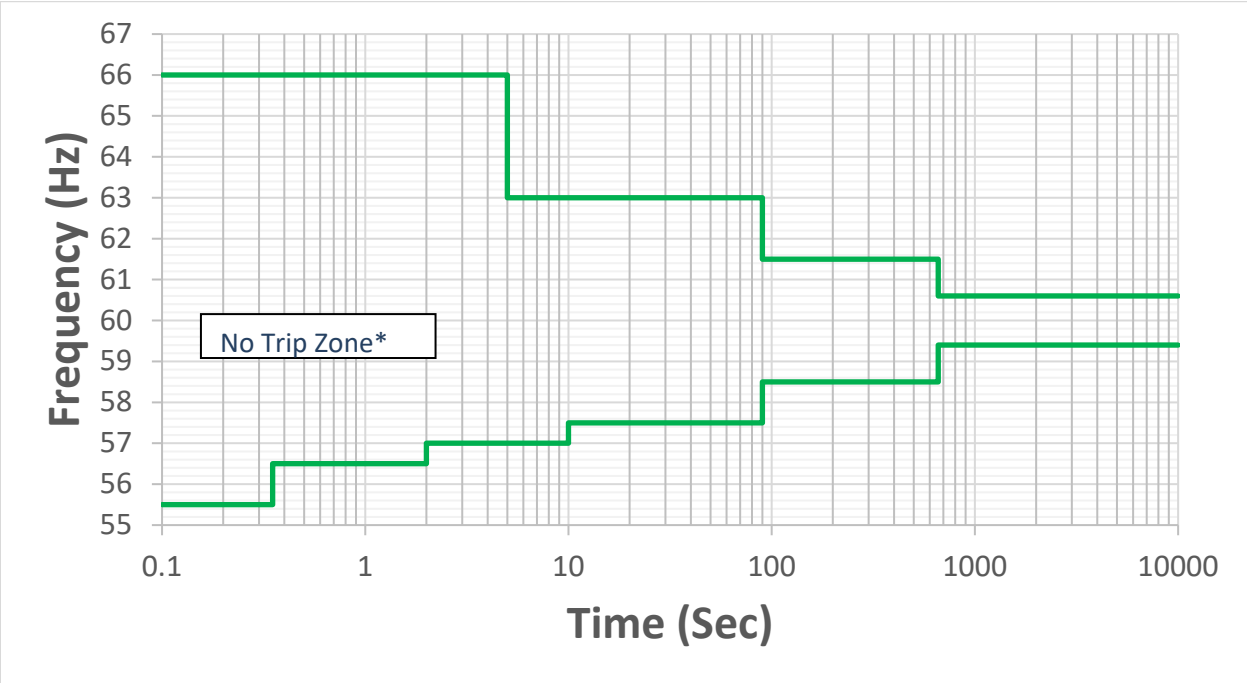

Figure 3: Quebec Interconnection Boundaries

**** 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

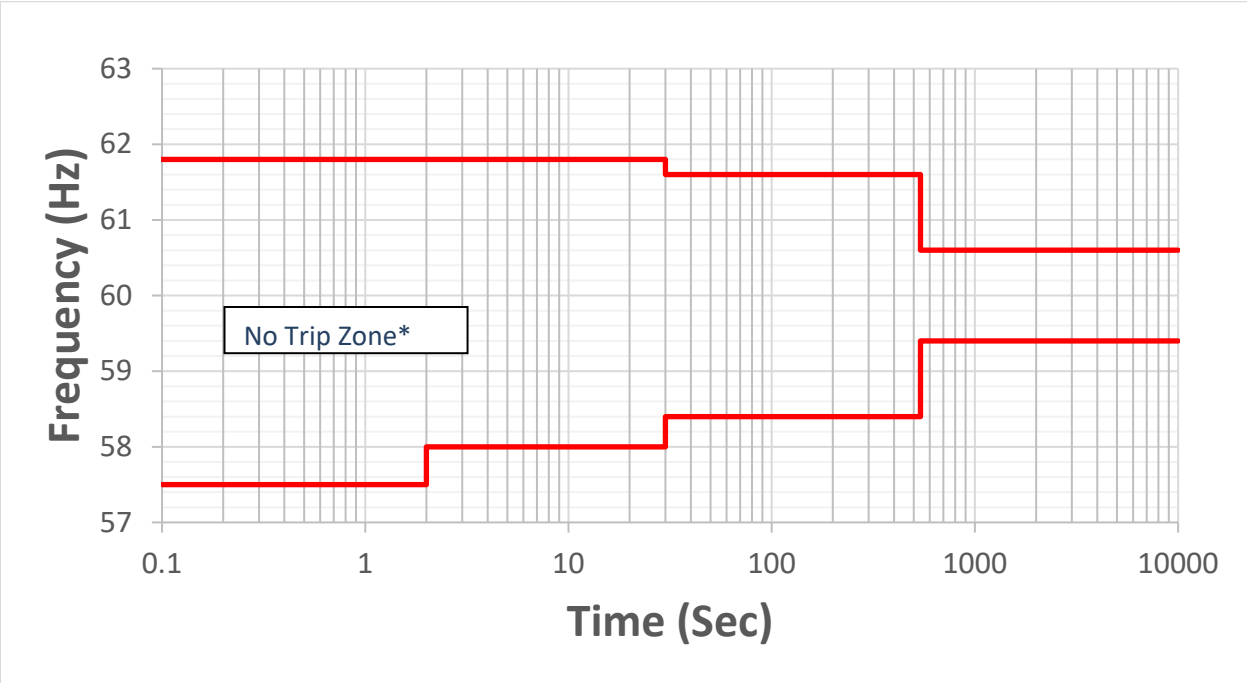

Figure 4: ERCOT Interconnection Boundaries

**** 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)

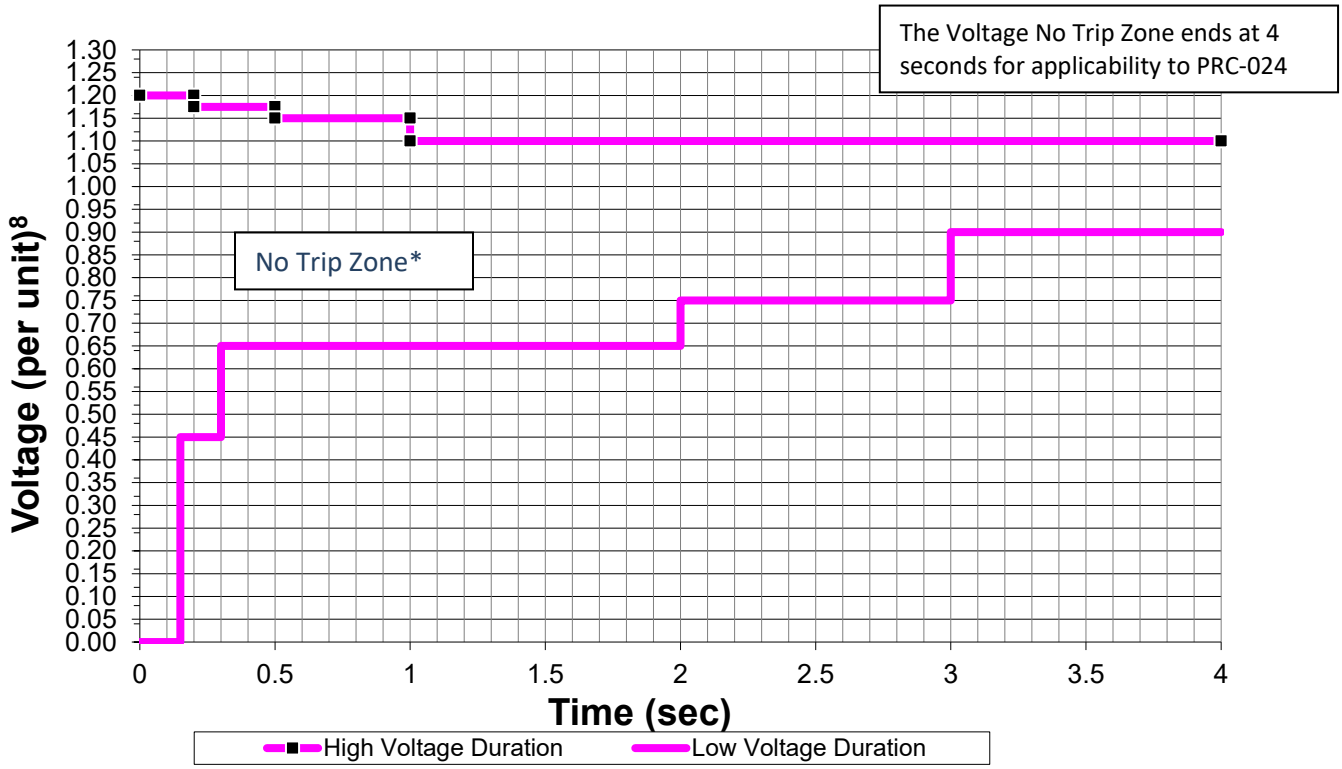

Figure 5: Voltage No-Trip Boundaries – Eastern, Western, and ERCOT Interconnections

**** 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)

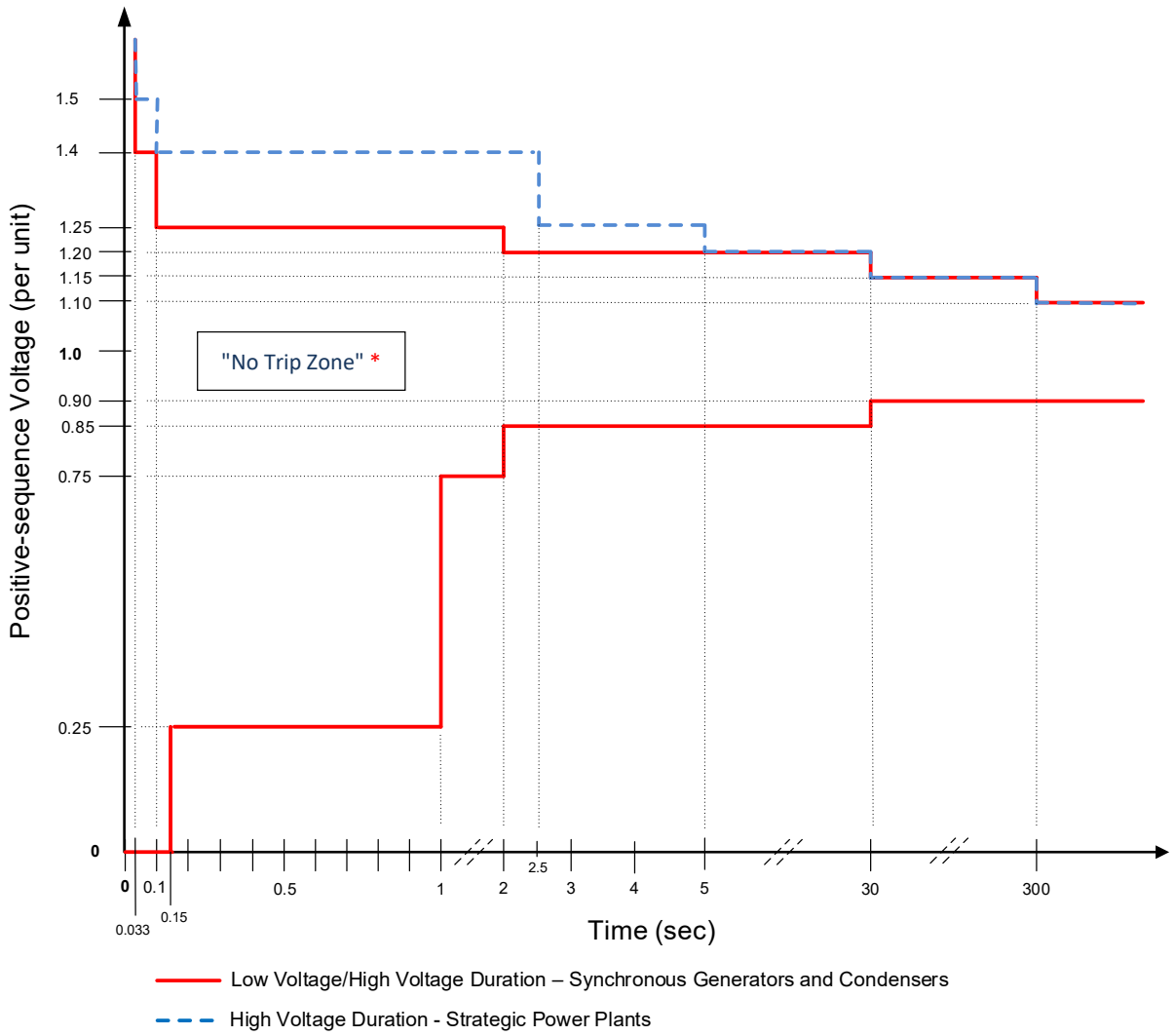

Figure 6: Voltage No-Trip Boundaries – Quebec Interconnection

**** 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.

A. Introduction

1. **Title:** **Frequency and Voltage Ride-through Requirements for Inverter-based Resources**

2. **Number:** **PRC-029-1**

3. **Purpose:** To ensure that IBRs Ride-through to support the Bulk Power System (BPS) during and after defined frequency and voltage excursions.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1. Generator Owner

   4.2 Facilities:

   4.2.1. Bulk Electric System (BES) IBRs

   4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Effective Date: See Implementation Plan for Project 2020-02 – PRC-029-1

Standard-only Definition: None

B. Requirements and Measures

R1. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements, in accordance with the "must Ride-through[1] zone" as specified in Attachment 1, except in the following conditions: *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

- The IBR needed to electrically disconnect in order to clear a fault;
- The voltage at the high-side of the main power transformer[2] went outside an accepted hardware limitation, in accordance with Requirement R4;
- The instantaneous positive sequence voltage phase angle change is more than 25 electrical degrees at the high-side of the main power transformer and is initiated by a non-fault switching event on the transmission system[3]; or
- The Volts per Hz (V/Hz) at the high-side of the main power transformer exceed 1.1 per unit for longer than 45 seconds or exceed 1.18 per unit for longer than 2 seconds.

M1. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R1. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) to demonstrate that the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R1. If the Generator Owner choose to utilize Ride-through exemptions that occur within the "must Ride-through zone" and are caused by non-fault initiated phase jumps of greater than 25 electrical degrees, then each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the IBR failed to Ride-through during a phase jump of greater than or equal to 25 electrical degrees, and documentation from their Transmission Planner, Reliability Coordinator, Planning Coordinator, or Transmission Operator that a non-fault initiated switching event occurred.

R2. Each Generator Owner shall ensure the design and operation is such that the voltage performance for each IBR adheres to the following during a voltage excursion, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

2.1. While the voltage at the high-side of the main power transformer remains within the continuous operation region as specified in Attachment 1, each IBR shall:

[1] Includes no tripping associated with phase lock loop loss of synchronism.
[2] For the purpose of this standard, the main power transformer is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for IBRs. In case of IBR connecting via a dedicated Voltage Source Converter High Voltage Direct Current (VSC-HVDC), the main power transformer is the main power transformer on the receiving end.
[3] Current blocking mode may be used for non-fault initiated phase jumps greater than 25 degrees in order to prevent tripping.

2.1.1 Continue to deliver the pre-disturbance level of Real Power or available Real Power[4], whichever is less.[5]

2.1.2 Continue to deliver Reactive Rower up to its Reactive Power limit and according to its controller settings.

2.1.3 Prioritize Real Power or Reactive Power when the voltage is less than 0.95 per unit, the voltage is within the continuous operating region, and the IBR cannot deliver both Real Power and Reactive Power due to a current limit or Reactive Power limit, unless otherwise specified through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.2. While voltage at the high-side of the main power transformer is within the mandatory operation region as specified in Attachment 1, each IBR shall exchange current, up to the maximum capability to provide voltage support, on the affected phases during both symmetrical and asymmetrical voltage disturbances, either under[6]:

- Reactive Power priority by default; or
- Real Power priority if required through other mechanisms by an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.

2.3. While voltage at the high-side of the main power transformer is within the permissive operation region, as specified in Attachment 1, each IBR may operate in current blocking mode if necessary to avoid tripping. Otherwise, each IBR shall follow the requirements for the mandatory operation region in Requirement R2.2.

2.3.1 If an IBR enters current blocking mode, it shall restart current exchange in less than or equal to five cycles of positive sequence voltage returning to a continuous operation region or mandatory operation region.

2.4. Each IBR shall not itself cause voltage at the high-side of the main power transformer to exceed the applicable high voltage thresholds and time durations in its response as voltage recovers from the mandatory or permissive operation regions to the continuous operation region.

2.5. Each IBR shall restore Real Power output to the pre-disturbance or available level[7] (whichever is lesser) within 1.0 second when the voltage at the high-side of the main power transformer returns from the mandatory operation region or

[4] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.
[5] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.
[6] In either case and if required, the magnitude of Real Power and reactive current shall be as specified by the Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator.
[7] "Available Real Power" refers to changes of facility Real Power output attributed to factors such as weather patterns, change of wind, and change in irradiance, but not changes of facility Real Power attributed to IBR tripping in whole or part.

permissive operation region (including operating in current blocking mode) to the continuous operation region, as specified in Attachment 1, unless an associated Transmission Planner, Planning Coordinator, Reliability Coordinator, or Transmission Operator requires a lower post-disturbance Real Power level requirement or requires a different post-disturbance Real Power restoration time through other mechanisms.[8]

M2. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to requirements, as specified in Requirement R2. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate that the operation of each IBR did adhere to performance requirements, as specified in Requirement R2, during each voltage excursion measured at the high-side of the main power transformer. Regarding R2.1.3, R2.2, and R2.5, the Generator Owner shall retain evidence of receiving such performance requirements, (e.g., email exchange, contract information) if the Transmission Planner, Transmission Operator, Reliability Coordinator, or Planning Coordinator has required the Generator Owner through other mechanisms to follow performance requirements other than those in Requirement R2 (e.g., ramp rates, Reactive Power prioritization).

R3. Each Generator Owner shall ensure the design and operation is such that each IBR meets or exceeds Ride-through requirements during a frequency excursion event whereby the System frequency remains within the "must Ride-through zone" according to Attachment 2 and the absolute rate of change of frequency (RoCoF)[9] magnitude is less than or equal to 5 Hz/second, unless a documented hardware limitation exists in accordance with Requirement R4. *[Violation Risk Factor: High] [Time Horizon: Operations Assessment]*

M3. Each Generator Owner shall have evidence to demonstrate the design of each IBR will adhere to Ride-through requirements, as specified in Requirement R3. Examples of evidence may include, but are not limited to dynamic simulations, studies, plant protection settings, and control settings design evaluation. Each Generator Owner shall also retain evidence of actual disturbance monitoring (i.e., sequence of event recorder, dynamic disturbance recorder, and fault recorder) data to demonstrate the operation of each IBR did adhere to Ride-through requirements, as specified in Requirement R3, during each frequency excursion event measured at the high-side of the main power transformer.

R4. Each Generator Owner identifying an IBR that is in-service by the effective date of PRC-029-1, has known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1-R3, and requires an exemption from specific

[8] Except if this would occur during a frequency excursion. The Real Power response should recover in accordance with the primary frequency controller.

[9] Rate of change of frequency (RoCoF) is calculated as the average rate of change for multiple calculated system frequencies for a time period of greater than or equal to 0.1 second. RoCoF is not calculated during the fault occurrence and clearance.

Ride-through criteria shall*:*[10] *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

4.1. Document information supporting the identified hardware limitation no later than 12 months following the effective date of PRC-029-1. This documentation shall include:

4.1.1 Identifying information of the IBR (name and facility number);

4.1.2 Which aspects of Ride-through requirements that the IBR would be unable to meet and the capability of the hardware due to the limitation;

4.1.3 Identification of the specific piece(s) of hardware causing the limitation;

4.1.4 Technical documentation verifying the limitation is due to hardware that would need to be physically replaced to meet all Ride-through criteria, and that the limitation cannot be remedied by software updates or setting changes; and

4.1.5 Information regarding any plans to remedy the hardware limitation (such as an estimated date).

4.2. Provide a copy of the information detailed in Requirement R4.1, except for any material considered by the original equipment manufacturer to be proprietary information, to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the Compliance Enforcement Authority (CEA) no later than 12 months following the effective date of PRC-029-1.[11]

4.2.1 Provide any response for additional information requested by the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and the CEA to the requestor within 90 days of the request.

4.2.2 Provide a copy of the acceptance of a hardware limitation by the CEA to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of receiving the acceptance.[12]

4.3. Each Generator Owner with a previously accepted limitation that replaces the hardware causing the limitation shall document and communicate such a hardware change to the associated Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), and Reliability Coordinator(s) within 90 days of the hardware change.

[10] The exemption requests for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

[11] To the extent the original equipment manufacturer considers any material to be proprietary, the Generator Owner is required to share this proprietary material only with the CEA.

[12] Acceptance by the CEA is verification that the information provided includes all information listed in Requirement R4.1.

4.3.1 When existing hardware causing the limitation is replaced, the exemption for that Ride-through criteria no longer applies.

M4. Each Generator Owner submitting for an exemption for an IBR that is in-service by the effective date of PRC-029-1, shall have evidence of submission to the CEA consistent with the information listed in Requirement R4.1. Each Generator Owner shall have evidence of communicated copies of each submission in accordance with Requirement R4.2 and to the associated entities described in Requirement R4.2. Acceptable types of evidence for submittals include, but are not limited to, meeting minutes, agreements, copies of procedures or protocols in effect, or email correspondence. Acceptable types of evidence for a hardware limitation may include, but is not limited to damage curves provided by the original equipment manufacturer. Each Generator Owner that receives a request for additional information under Requirement R4.2.1 shall have evidence of providing that information within 90 days. Each Generator Owner that replaces hardware at an IBR that is directly associated with an accepted exemption and that hardware is the cause for the limitation, shall have evidence of communicating the hardware change to the associated entities described in Requirement R4.3 within 90 days of the hardware replacement.

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.

- Each Generator Owner shall retain evidence with Requirements R1, R2, and R3 in this standard for 36 calendar months or the date of the last audit, whichever is greater.
- Each Generator Owner shall retain evidence with Requirement R4 in this standard for five calendar years or the date of the last audit, whichever is greater.

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.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 1, except for those conditions identified in Requirement R1.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 1, except for those conditions identified in Requirement R1.
R2.	The Generator Owner failed to ensure the design capability of each applicable IBR to adhere to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to performance requirements during voltage excursions, as specified in Requirement R2, unless a documented hardware limitation exists in accordance with Requirement R4.
R3.	The Generator Owner failed to ensure the design capability of each applicable IBR to Ride-through in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.	N/A	N/A	The Generator Owner failed to ensure each applicable IBR adhered to Ride-through requirements in accordance with Attachment 2, unless a documented hardware limitation exists in accordance with Requirement R4.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R4.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 12 months, but less than or equal to 15 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 90 days but less than or equal to 120 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 90 days but less than or equal to 120 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 15 months, but less than or equal to 18 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 120 days, but less than or equal to 150 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 120 days but less than or equal to 150 days after receiving the acceptance of a hardware limitation by the CEA.	The Generator Owner provided a copy to the applicable entities as detailed in Requirement R4.2 more than 18 months, but less than or equal to 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 150 days but less than or equal to 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.2 more than 150 days but less than or equal to 180 days after receiving the acceptance of a hardware limitation by the CEA. OR	The Generator Owner failed to document complete information for IBR identified with known hardware limitations that prevent the IBR from meeting Ride-through criteria as detailed in Requirements R1, R2, or R3. OR The Generator Owner failed to provide a copy to the applicable entities as detailed in Requirement R4.2 within 24 months after the effective date of Requirement R4. OR The Generator Owner failed to respond to the applicable entities as detailed in Requirement R4.2.1 more than 180 days after receiving a request for additional information by an entity listed in Requirement R4.2.1. OR The Generator Owner failed to respond to the applicable

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s), Reliability Coordinator(s), and CEA more than 90 calendar days but less than or equal to 120 calendar days after the change to the hardware.	OR The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 120 calendar days but less than or equal to 150 calendar days after the change to the hardware.	The Generator Owner with a previously communicated hardware limitation that replaces the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Reliability Coordinator(s), Transmission Operator(s), and CEA more than 150 calendar days but less than or equal to 180 calendar days after the change to the hardware.	entities as detailed in Requirement R4.2.2 more than 180 days after receiving the acceptance of a hardware limitation by the CEA. The Generator Owner with a previously communicated hardware limitation that replace the documented limiting hardware but failed to document and communicate the change to its Planning Coordinator(s), Transmission Planner(s), Transmission Operator(s),Reliability Coordinator(s), and CEA more than 180 days after the change to the hardware.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan .

Version History

Version	Date	Action	Change Tracking
1	October 8, 2024	Draft 4 approved by the NERC Board of Trustees	Developed under Project 2020-02
1	October 16, 2024	Draft 4 errata approved by the Standards Committee	Approved errata

Attachment 1: Voltage Ride-Through Criteria

Table 1: Voltage Ride-through Requirements for AC-Connected Wind IBR [13]

Voltage (per unit)[14]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[15]	N/A
≥ 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	3.00
< 0.70	Mandatory Operation Region	2.50
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.16
< 0.10	Permissive Operation Region	0.16

Table 2: Voltage Ride-through Requirements for All Other IBR

Voltage (per unit)[16]	Operation Region	Minimum Ride-Through Time (sec)
> 1.20	N/A[17]	N/A
> 1.10	Mandatory Operation Region	1.0
> 1.05	Continuous Operation Region	1800
≤ 1.05 and ≥ 0.90	Continuous Operation Region	Continuous
< 0.90	Mandatory Operation Region	6.00
< 0.70	Mandatory Operation Region	3.00
< 0.50	Mandatory Operation Region	1.20
< 0.25	Mandatory Operation Region	0.32
< 0.10	Permissive Operation Region	0.32

1. Table 1 applies to type 3 and type 4 wind IBR or hybrid IBR that include wind, unless connected via a dedicated Voltage Source Converter - High Voltage Direct Current (VSC-HVDC) transmission facility.
2. Table 2 applies to all other IBR types not covered in Table 1; including, but not limited to, the following facilities:

[13] Type 3 and type 4 wind resources directly connected to the AC Transmission System.
[14] Refer to bullet #4 below.
[15] These conditions are referred to as the "may Ride-through zone".
[16] Refer to bullet #4 below.
[17] These conditions are referred to as the "may Ride-through zone".

a. IBR, regardless of their energy resource, interconnecting via a dedicated VSC-HVDC transmission facility.

b. Other IBR or hybrid IBR consisting of photovoltaic (PV) and BESS.

3. The applicable voltage for VSC-HVDC system with a dedicated connection to an IBR is on the AC side of the transformer(s) that is (are) used to connect the VSC-HVDC system to the interconnected transmission system.

4. The voltage base for per unit calculation is the nominal phase-to-ground or phase-to-phase transmission system voltage unless otherwise defined by the Planning Coordinator, Transmission Planner, or Transmission Owner.

5. The applicable voltage for Tables 1 and 2 is identified as the voltage max/min of phase-to-neutral or phase-to-phase fundamental root mean square (RMS) voltage at the high-side of the main power transformer.

6. Tables 1 and 2 are only applicable when the frequency is within the "must Ride-through zone" as specified in Figure 1 of Attachment 2.

7. At any given voltage value, each IBR shall Ride-through unless the time duration at that voltage has exceeded the specified minimum Ride-through time duration. If the voltage is continuously varying over time, it is necessary to add the duration within each band of Tables 1 and 2 over any 10 second time period.

8. The specified duration of the mandatory operation regions and the permissive operation regions in Tables 1 and 2 is cumulative over one or more disturbances within any 10 second time period.

9. The IBR may trip for more than four deviations of the applicable voltage at the high-side of the main power transformer outside of the continuous operation region within any 10 second time period.

10. Instantaneous trip settings based on instantaneously calculated voltage measurements with less than filtering lengths of one cycle (16.6 millisecond) are not permissible.

11. The "must Ride-through zone" is the combined area of the mandatory operating regions, the continuous operating regions, and the permissive operating region. All area outside of these operating regions is referred to as the "may Ride-through zone".

Attachment 2: Frequency Ride-Through Criteria

Table 3: Frequency Ride-through Capability Requirements

System Frequency (Hz)	Minimum Ride-Through Time (sec)
> 61.8	May trip
> 61.2	299
≤ 61.2 and ≥ 58.8	Continuous
< 58.8	299
< 57.0	May trip

1. Frequency measurements are taken at the high-side of the main power transformer.
2. Frequency is measured over a period of time (typically 3-6 cycles) to calculate system frequency at the high-side of the main power transformer.
3. Instantaneous or single points of measurement may not be used in the determination of control settings.
4. At any given frequency value, each IBR shall Ride-through unless the time duration at that frequency has exceeded the specified minimum ride-through time duration.
5. The specified durations of Table 3 are cumulative over one or more disturbances within a 10-minute time period.

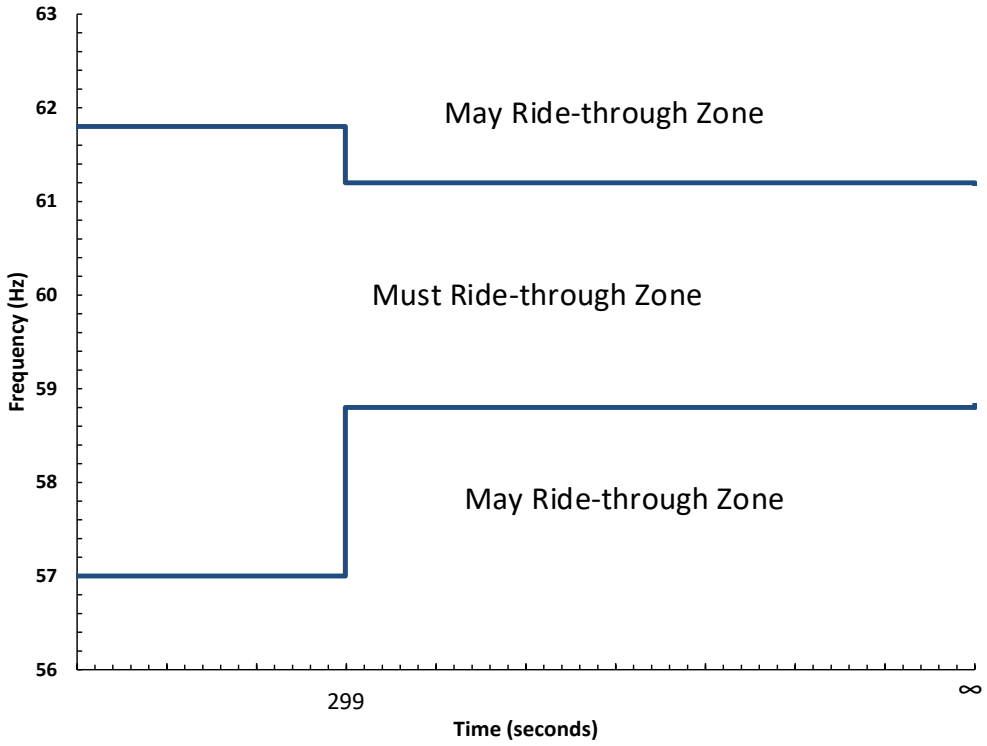

Figure 1: PRC-029 Frequency Ride-through Requirements