Board Report

	☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	The current definition of the term POI requires that a POI must be at a substation (at a specified voltage level) but also that this substation must be reflected in the Standard Generation Interconnection Agreement (SGIA). This is problematic not only because many Generation Resources that are either older or Non-Opt-In Entity (NOIE)-owned do not have an SGIA, but also because the SGIA in Section 1.14 defines the POI to be the point where ownership changes from the generator to the Transmission Service Provider (TSP), and in many cases, the POI designated in the SGIA is at some location other than the substation. In these cases, it is not clear what point should be considered the POI under the definition of that term. In many cases where the term POI is used in the Protocols, the meaning is material to the application of the provision. For example, in paragraph (1) of Protocol Section 10.3.2.2, Loss Compensation of EPS Meter Data, POI must be understood to refer to the point of ownership change, and not necessarily the TSP's substation, because the provision applies only when "the EPS Meter is not located at the [POI]" and would therefore have no meaning if the POI was always understood to be at the substation where the EPS Meter is located. In other cases, such as with the Voltage Support Service (VSS) requirements in Protocol Section 3.15, Voltage Support, and Protocol Section 6.5.7.7, Voltage Support Service, POI must be understood to refer to a TSP-owned substation because the TSP metering equipment used to monitor voltage is always located at the substation, and not necessarily at the point of ownership change defined in the SGIA. Given these differing uses of the term POI, ERCOT has concluded that two terms are necessary—one to refer to the point of ownership change, consistent with the definition in the SGIA, and one to refer to the substation downstream of the point of ownership change, or more precisely, to one or more buses in that substation (given that electrical differences may exist at different buses in the same substation, and that, for all instances in the Protocols where POI should be understood to refer to the downstream substation, bus-level measurements appear to be appropriate). For the sake of consistency with the SGIA, ERCOT proposes to modify the existing term POI to conform to the SGIA's conception of the POI as the point

	of ownership change. At the same time, ERCOT proposes to remove the reference to the SGIA in that definition, since NOIE generators and certain older generators may not have an SGIA. For the purpose of existing POI references that may be reasonably understood to refer to some point in the TSP's substation downstream of that point of ownership change, ERCOT is proposing a new term POIB.
ROS Decision	On 6/4/20, ROS voted unanimously via roll call to table NOGRR210. All Market Segments participated in the vote. On 9/3/20, ROS voted unanimously via roll call to recommend approval of NOGRR210 as submitted. All Market Segments participated in the vote. On 10/8/20, ROS voted unanimously via roll call to endorse and forward to TAC the 9/3/20 ROS Report, as amended by the 10/6/20 ERCOT comments, and Impact Analysis for NOGRR210. All Market Segments participated in the vote.
Summary of ROS Discussion	On 6/4/20, participants determined to table NOGRR210 for further discussion. On 9/3/20, there was no discussion. On 10/8/20, ERCOT Staff noted revisions proposed in the 10/6/20 ERCOT comments to NOGRR210.
TAC Decision	On 10/28/20, TAC voted unanimously via roll call to table NOGRR210. All Market Segments participated in the vote. On 6/23/21, TAC voted unanimously via roll call to recommend approval of NOGRR210 as recommended by ROS in the 10/8/20 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/28/20, participants discussed tabling NOGRR210 to await the related NPRR1005. On 6/23/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of NOGRR210.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR210 and believes the market impact for NOGRR210 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board voted to recommend approval of NOGRR210 as recommended by TAC in the 6/23/21 TAC Report.

Board Report

Sponsor	
Name	Jay Teixeira
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Company	ERCOT
Phone Number	512-248-6582
Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
ERCOT 100620	Proposed grey box revisions to accommodate baseline updates

Market Rules Notes

Please note the baseline language in the following section has been updated to reflect the incorporation of the following NOGRR into the Nodal Operating Guide:

- NOGRR187, Related to NPRR863, Creation of ERCOT Contingency Reserve Service and Revisions to Responsive Reserve (partially unboxed 3/1/20)
  - Section 2.3
- NOGRR195, Generator Voltage Control Tolerance Band (unboxed 2/5/21)
  - Section 2.2.10
  - Section 2.7.3.3
  - Section 2.7.3.4
- NOGRR196, Related to NPRR973, Add Definitions for Generator Step-Up and Main Power Transformer (incorporated 9/1/20)
  - Section 3.3.2.1
- NOGRR204, Related to NPRR989, BESTF-1 Energy Storage Resource Technical Requirements (incorporated 7/1/20)
  - Section 2.2.5
  - Section 2.7.3.2
  - Section 2.7.3.4

  - Section 2.9.1
  - Section 3.3.2.1
  - Section 3.3.2.2
  - Section 8C
- NOGRR209, Related to NPRR1003, Elimination of References to Resource Asset Registration Form (incorporated 9/1/20)
  - Section 2.2.5
  - Section 3.3.2.1
- NOGRR211, RTC – NOG 2 and 9: System Operations and Control Requirements and Monitoring Programs (incorporated 1/1/21)
  - Section 2.3
- NOGRR212, Related to NPRR1016, Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) (incorporated 9/1/20)
  - Section 2.2.10
  - Section 2.7.3.2
  - Section 2.7.3.3
  - Section 2.9.1
- NOGRR220, Greybox Baseline Updates re NOGRR212 (incorporated 12/1/20)
  - Section 2.2.10
  - Section 2.7.3.2
  - Section 2.7.3.3
  - Section 2.9.1

Proposed Guide Language Revision

2.2.5 Automatic Voltage Regulators

(1) A Resource Entity shall immediately notify its QSE and its interconnecting TO of any change in Automatic Voltage Regulator (AVR) status (i.e., AVR unavailability due to maintenance or failure and when the AVR returns to normal operation). A QSE shall immediately notify ERCOT of any change in AVR status and shall supply AVR status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status.

(2) Resource Entities shall conduct tests for the purpose of model verification on AVRs or verify AVR performance through comparison with operational data a minimum of every ten calendar years. All new Generation Resources shall conduct an AVR test as prescribed in paragraph (4) of Protocol Section 8.1.1.2.1.4, Voltage Support Service Qualification, within five years of the initial AVR test approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if equipment characteristics are knowingly modified, an AVR test shall be conducted within 120 days of the modification. Industry accepted testing techniques shall be used for testing, measuring and calculating the modeling parameters. The test report must list the test(s) conducted or include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard Power

System Simulator for Engineering (PSS/E) dynamic model or ERCOT and Transmission Service Provider (TSP) approved user written model.

(a) Resource Entities will provide the test data or verified dynamic models to ERCOT by submittal to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area or by updating its Resource Registration information respectively.

(b) All devices included in the AVR control system including but not limited to synchronous condensers, static Volt-Ampere reactive (VAr) compensators, static synchronous compensators (STATCOMs), and switchable shunt reactive devices required to meet Protocol Section 3.15, Voltage Support, shall be included in the AVR test and set to regulate the transmission level voltage at the Point of Interconnection Bus (POIB).

[NOGRR204: Replace paragraph (2) above with the following upon system implementation of NPRR989:]

(2) Resource Entities shall conduct tests for the purpose of model verification on AVRs or verify AVR performance through comparison with operational data a minimum of every ten calendar years. All new Generation Resources and Energy Storage Resources (ESRs) shall conduct an AVR test as prescribed in paragraph (4) of Protocol Section 8.1.1.2.1.4, Voltage Support Service Qualification, within five years of the initial AVR test approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if equipment characteristics are knowingly modified, an AVR test shall be conducted within 120 days of the modification. Industry accepted testing techniques shall be used for testing, measuring and calculating the modeling parameters. The test report must list the test(s) conducted or include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard Power System Simulator for Engineering (PSS/E) dynamic model or ERCOT and Transmission Service Provider (TSP) approved user written model.

(a) Resource Entities will provide the test data or verified dynamic models to ERCOT by submittal to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area or by updating its Resource Registration information respectively.

(b) All devices included in the AVR control system including but not limited to synchronous condensers, static Volt-Ampere reactive (VAr) compensators, static synchronous compensators (STATCOMs), and switchable shunt reactive devices required to meet Protocol Section 3.15, Voltage Support, shall be included in the AVR test and set to regulate the transmission level voltage at the Point of Interconnection Bus (POIB).

(3) Resource Entities shall verify excitation systems model data upon initial installation, within 120 days of performance modifications, and a minimum of ten calendar years thereafter.

(4) An exemption may be granted for the testing requirements listed in paragraphs (2) and (3) above if the Resource on which the AVR or excitation system is installed has an Annual Net Capacity Factor (ANCF) of 5% or less over the most recent three calendar years preceding the planned testing calendar year. ANCF is calculated as follows:

Annual Total Net Generation in MWHr/(Annual Hours * Average Seasonal Net Max Sustainable Rating) * 100%

Wherein:

Annual Hours = Number of hours in the calendar year being reported. Hours in mothball or retired status are not included in the hour total;

and

Average Seasonal Net Max Sustainable Rating = Average of the Seasonal Net Max Sustainable ratings submitted via the NDCRC application located on the MIS Secure Area.

(a) At the end of this ten year timeframe, the current average three year ANCF (for years eight, nine, and ten) will be examined by ERCOT to determine if the exemption can be declared for the next ten year period. If no longer eligible for exemption based on the ANCF, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. Under certain operating conditions, ERCOT may require a ten year test even if the current average three year ANCF is below the 5% threshold.

(5) Black Start designated units are not eligible for the ANCF exemption detailed in paragraph (4) above. If a Resource that had been granted an exemption detailed in paragraph (4) above is accepted for Black Start Service (BSS), the Resource has 365 days from the start date of BSS to submit modeling information detailed in paragraph (2) above.

(6) Generation Resource AVR modeling information required in the ERCOT Planning Criteria shall be determined from actual Generation Resource testing described in these Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the TSP.

[NOGRR204: Replace paragraph (6) above with the following upon system implementation of NPRR989:]

(6) Generation Resource or ESR AVR modeling information required in the ERCOT Planning Criteria shall be determined from actual Generation Resource or ESR testing

described in these Operating Guides. Within 30 days of ERCOT's request, the results of the latest test performed shall be supplied to ERCOT and the TSP.

2.2.10 Generation Resource Response Time Requirements

(1) All Generation Resources providing Voltage Support Service (VSS) as described in Protocol Section 3.15, Voltage Support, shall maintain the necessary procedures and processes plus communications, telemetry, remote control, automation, and staffing in order to normally comply with the response times listed below when a VSS Dispatch Instruction or a TO Voltage Set Point instruction, as described in Protocol Section 6.5.7.7, Voltage Support Service, is given. Compliance is based upon normal operating conditions where VSS Dispatch Instructions respect all equipment operating limits and other restrictions that are periodically placed on equipment. The response time to a VSS Dispatch Instruction or a TO Voltage Set Point instruction shall commence with the successful receipt by the QSE or Generation Resource either through a verbal or telemetered instruction.

(2) A Resource Entity, TO, or QSE is not required to comply with a VSS Dispatch Instruction or Voltage Set Point instruction if compliance with such an instruction is impossible due to either a Force Majeure Event or one or more of the conditions described in paragraphs (1) and (2) of Protocol Section 6.5.7.9, Compliance with Dispatch Instructions. In the event compliance with an instruction is precluded under this paragraph:

(a) An affected Resource Entity shall, as soon as practicable, notify its QSE, and the Resource Entity or its QSE shall, as soon as practicable, but not longer than 15 minutes from receipt of the instruction by the Resource Entity, notify the Entity issuing the instruction; and

(b) An affected TO shall, as soon as practicable, but not longer than 15 minutes from notification from the Resource Entity or its QSE, notify ERCOT.

(3) The required VSS response times for Generation Resources are:

(a) For automatically switchable static VAr capable devices, when voltage or reactive measurements at the POIB are outside of the Voltage Set Point tolerance band identified in paragraph (4) of Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements; then the response must be fully deployed in no more than five minutes. If a TO and a Resource Entity have determined that a longer response time is appropriate and have entered into a written agreement reflecting that response time, then the Generation Resource shall be required to comply with that agreed response time so long as it does not exceed ten minutes.

(b) Response to a TO Voltage Set Point instruction shall be completed in no more than five minutes from receipt of the instruction.

(c) Response to a VSS Dispatch Instruction that requires a change to the real power output of the Generation Resource shall be completed as soon as practicable.

(4) Shutting down and disconnecting Generation Resources from the ERCOT Transmission Grid:

(a) On-Line Generation Resources must be able to commence their shutdown sequence within five minutes of receipt of a Dispatch Instruction from ERCOT. Nuclear-fueled Generation Resources shall comply with the procedural requirements of the Nuclear Regulatory Commission (NRC) when receiving Dispatch Instructions from ERCOT to disconnect the Generation Resource from the ERCOT Transmission Grid.

(b) If the ERCOT Transmission Grid condition requires breaker or switch operations to disconnect a non-MW producing generator from the system, such operations shall be completed as soon as practicable, but no longer than 15 minutes of the receipt of a Dispatch Instruction from ERCOT. Once disconnected from the ERCOT Transmission Grid, a Generation Resource shall complete as soon as practicable, but no longer than 15 minutes, the required switching to return the system to a normal configuration except for nuclear-fueled Generation Resources, which shall comply with the procedural requirements of the NRC when receiving Dispatch Instructions from ERCOT to disconnect the Generation Resource from the ERCOT Transmission Grid.

[NOGRR204 and NOGRR212: Replace applicable portions of Section 2.2.10 above with the following upon system implementation of NPRR989 or NPRR1016, respectively:]

2.2.10 Generation Resource and Energy Storage Resource Response Time Requirements

(1) All Generation Resources and ESRs providing Voltage Support Service (VSS) as described in Protocol Section 3.15, Voltage Support, shall maintain the necessary procedures and processes plus communications, telemetry, remote control, automation, and staffing in order to normally comply with the response times listed below when a VSS Dispatch Instruction or a TO Voltage Set Point instruction, as described in Protocol Section 6.5.7.7, Voltage Support Service, is given. Compliance is based upon normal operating conditions where VSS Dispatch Instructions respect all equipment operating limits and other restrictions that are periodically placed on equipment. The response time to a VSS Dispatch Instruction or a TO Voltage Set Point instruction shall commence with the successful receipt by the QSE, Generation Resource, or ESR either through a verbal or telemetered instruction.

(2) A Resource Entity, TO, or QSE is not required to comply with a VSS Dispatch Instruction or Voltage Set Point instruction if compliance with such an instruction is impossible due to either a Force Majeure Event or one or more of the conditions described in paragraphs (1) and (2) of Protocol Section 6.5.7.9, Compliance with Dispatch Instructions. In the event compliance with an instruction is precluded under this

paragraph:

(a) An affected Resource Entity shall, as soon as practicable, but not longer than 15 minutes from receipt of the instruction by the Resource Entity, notify its QSE, and the Resource Entity or its QSE shall, as soon as practicable, notify the Entity issuing the instruction; and

(b) An affected TO shall, as soon as practicable, but not longer than 15 minutes from notification from the Resource Entity or its QSE, notify ERCOT.

(3) The required VSS response times for Generation Resources and ESRs are:

(a) For automatically switchable static VAr capable devices, when voltage or reactive measurements at the POIB are outside of the Voltage Set Point tolerance band identified in paragraph (4) of Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource or ESR Requirements; then the response must be fully deployed in no more than five minutes. If a TO and a Resource Entity have determined that a longer response time is appropriate and have entered into a written agreement reflecting that response time, then the Generation Resource or ESR shall be required to comply with that agreed response time so long as it does not exceed ten minutes.

(b) Response to a TO Voltage Set Point instruction shall be completed in no more than five minutes from receipt of the instruction.

(c) Response to a VSS Dispatch Instruction that requires a change to the real power output of the Generation Resource or ESR shall be completed as soon as practicable.

(4) Shutting down and disconnecting Generation Resources or ESRs from the ERCOT System:

(a) On-Line Generation Resources or ESRs must be able to commence their shutdown sequence within five minutes of receipt of a Dispatch Instruction from ERCOT. Nuclear-fueled Generation Resources shall comply with the procedural requirements of the Nuclear Regulatory Commission (NRC) when receiving Dispatch Instructions from ERCOT to disconnect the Generation Resource from the ERCOT Transmission Grid. Additionally, Distribution Generation Resources (DGRs) or Distribution Energy Storage Resources (DESRs) must be able to shut down their generators in a timeframe that meets the requirements of their Distribution Service Provider (DSP). Once disconnected from the ERCOT System, the QSE shall update the DGR or DESR's Current Operating Plan (COP) as soon as practicable of plans to reconnect to the ERCOT System.

(b) If the ERCOT Transmission Grid condition requires breaker or switch operations to disconnect a non-MW producing Generation Resource or ESR from the system, such operations shall be completed as soon as practicable, but no longer than 15 minutes of the receipt of a Dispatch Instruction from ERCOT. Once disconnected

from the ERCOT Transmission Grid, a Generation Resource or ESR shall complete as soon as practicable, but no longer than 15 minutes, the required switching to return the system to a normal configuration except for nuclear-fueled Generation Resources, which shall comply with the procedural requirements of the NRC when receiving Dispatch Instructions from ERCOT to disconnect the Generation Resource from the ERCOT Transmission Grid.

2.3 Ancillary Services

(1) The types of Ancillary Services required by ERCOT are described below:

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Regulation Down Service (Reg-Down) and Regulation Up Service (Reg-Up) (for Generation Resources) ***Reference: Protocol Section 2, Definitions and Acronyms***	Resource capacity provided by a Qualified Scheduling Entity (QSE) from a specific Generation Resource to control frequency within the system which is controlled second by second, normally by an Automatic Generation Control (AGC) system.	a. Reg-Down energy is a deployment to increase or decrease generation at a level below the Generation Resource's Base Point in response to a change in system frequency. b. Reg-Up energy is a deployment to increase or decrease generation at a level above the Generation Resource's Base Point in response to a change in system frequency.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Reg-Down and Reg-Up (for Load Resource) ***Reference: Protocol Section 2***	Load Resource capacity provided by a QSE from a specific Load Resource to control frequency within the system.	a. Reg-Down is a deployment to increase or decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's Maximum Power Consumption (MPC) limit in response to a change in system frequency. b. Reg-Up is a deployment to increase or decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Load Resource's Low Power Consumption (LPC) limit in response to a change in system frequency.
Responsive Reserve (RRS) ***Reference: Protocol Section 2***	Operating reserves on Generation Resources, Load Resources, and Resources capable of providing Fast Frequency Response (FFR) maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources and Controllable Load can be used as energy during an Energy Emergency Alert (EEA) event.	RRS may only be deployed as follows: a. Through automatic Governor action or under-frequency relay in response to frequency deviations; b. By electronic signal from ERCOT in response to the need; and c. As ordered by an ERCOT Operator during an EEA or other emergencies.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Non-Spinning Reserve (Non-Spin) Service ***Reference: Protocol Section 2***	a. Off-Line Generation Resource capacity, or reserved capacity from On-Line Generation Resources, capable of being ramped to a specified output level within 30 minutes, and operating at a specified output for the entire duration of the Non-Spin obligation. b. Controllable Load Resources that are capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for the entire duration of the Non-Spin obligation.	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
Voltage Support Service (VSS) ***Reference: Protocol Section 3.15, Voltage Support***	Reactive capability of a Generation Resource that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits. All Generation Resources with a gross rating greater than 20 MVA shall provide VSS.	Direct the scheduling of VSS by providing Voltage Profiles at the Point of Interconnection Bus (POIB). The Generation Resource is obligated to maintain the published voltage profile within its Corrected Unit Reactive Limit (CURL).
Black Start Service (BSS) ***Reference: Protocol Section 3.14.2, Black Start***	The provision of Generation Resources under a Black Start Agreement, which are capable of self-starting without support from within ERCOT in the event of a Partial Blackout or Blackout.	Provide emergency Dispatch Instructions to begin restoration to a secure operating state after a Partial Blackout or Blackout.
Reliability Must-Run (RMR) Service ***Reference: Protocol Section 3.14.1, Reliability Must Run***	The provision of Generation Resource capacity and energy under an RMR Agreement.	Enter into contractual agreements to retain units required for reliable operations. Direct the operation of those units that otherwise would not operate and that are necessary to provide reliable operations.

[NOGRR187, NOGRR204, and NOGRR211: Replace applicable portions of paragraph (1) above with the following upon system implementation of NPRR863, NPRR989, or NPRR1007, respectively:]

(1) The types of Ancillary Services required by ERCOT are described below:

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Regulation Down Service (Reg-Down) and Regulation Up Service (Reg-Up) (for Generation Resources and Energy Storage Resources (ESRs)) ***Reference: Protocol Section 2, Definitions and Acronyms***	Resource capacity provided by a Qualified Scheduling Entity (QSE) from a specific Generation Resource or ESR to control frequency within the system which is controlled second by second, normally by an Automatic Generation Control (AGC) system.	a. Reg-Down energy is a Resource-specific deployment to increase or decrease generation at a level below the Generation Resource's or ESR's Base Point in response to a change in system frequency. b. Reg-Up energy is a Resource-specific deployment to increase or decrease generation at a level above the Generation Resource's or ESR's Base Point in response to a change in system frequency.
Reg-Down and Reg-Up (for Load Resource) ***Reference: Protocol Section 2***	Load Resource capacity provided by a QSE from a specific Load Resource to control frequency within the system.	a. Reg-Down is a Resource-specific deployment to increase or decrease Load below the Load Resource's Maximum Power Consumption (MPC) limit in response to a change in system frequency. b. Reg-Up is a Resource-specific deployment to increase or decrease Load above the Load Resource's Low Power Consumption (LPC) limit in response to a change in system frequency.

Responsive Reserve (RRS) ***Reference: Protocol Section 2***	Operating reserves on Generation Resources, ESRs, Load Resources, and Resources capable of providing Fast Frequency Response (FFR) maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources, ESRs, and Controllable Load can be used as energy during an Energy Emergency Alert (EEA) event.	RRS may only be deployed as follows: a. Through automatic Governor action or under-frequency relay in response to frequency deviations; b. By electronic signal from ERCOT in response to the need; and c. As ordered by an ERCOT Operator during an EEA or other emergencies.
ERCOT Contingency Reserve Service (ECRS) ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within ten minutes, and operating at a specified output for at least one hour. b. Controllable Load Resources dispatchable by SCED that are capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for at least one hour. c. Load Resources other than Controllable Load Resources that may or may not be controlled by under-frequency relay that are capable of interrupting within ten minutes at ERCOT instruction for at least one hour	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service.

Non-Spinning Reserve (Non-Spin) Service ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within 30 minutes, and operating at a specified output for at least one hour. b. Controllable Load Resources that are capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for at least one hour.	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
Voltage Support Service (VSS) ***Reference: Protocol Section 3.15, Voltage Support***	Reactive capability of a Generation Resource or ESR that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits. All Generation Resources and ESRs with a gross rating greater than 20 MVA shall provide VSS.	Direct the scheduling of VSS by providing Voltage Profiles at the Point of Interconnection Bus (POIB). The Generation Resource or ESR is obligated to maintain the published voltage profile within its Corrected Unit Reactive Limit (CURL).
Black Start Service (BSS) ***Reference: Protocol Section 3.14.2, Black Start***	The provision of Generation Resources under a Black Start Agreement, which are capable of self-starting without support from within ERCOT in the event of a Partial Blackout or Blackout.	Provide emergency Dispatch Instructions to begin restoration to a secure operating state after a Partial Blackout or Blackout.
Reliability Must-Run (RMR) Service ***Reference: Protocol Section 3.14.1, Reliability Must Run***	The provision of Generation Resource capacity and energy under an RMR Agreement.	Enter into contractual agreements to retain units required for reliable operations. Direct the operation of those units that otherwise would not operate and that are necessary

		to provide reliable operations.	

2.7.3.2 ERCOT Responsibilities

(1) ERCOT shall be responsible for ordering necessary generation On-Line to regulate transmission voltage and reactive flow.

(2) When voltage levels deviate from normal operating limits in the pre-contingency (base case) condition or from emergency operating limits in the post-contingency condition, ERCOT shall take immediate steps to restore voltage levels within the applicable operating limits using all available reactive resources. ERCOT may allow additional time for a TO to correct the voltage levels to within limits on sub-100kV facilities prior to ERCOT taking further steps to restore voltage levels. The steps ERCOT may take include, but are not limited to:

(a) Evaluating TO actions taken to correct voltage levels;

(b) Directing additional Generation Resources On-Line;

(c) Redispatching generation;

(d) Deploying additional Resources;

(e) Directing static Reactive Power resources to be put in service;

(f) Utilizing temporary changes to limits of Resources or Transmission Facilities;

(g) Developing a Constraint Management Plan (CMP);

(h) Adjusting a Voltage Set Point; and

(i) Shedding firm Load.

(3) ERCOT shall issue a VSS Dispatch Instruction to the designated QSE for adjustments that would require a Generation Resource to operate outside its Unit Reactive Limit (URL).

(4) For multi-generator busses, ERCOT may not instruct any single Generation Resource to operate beyond its Corrected Unit Reactive Limit (CURL) or URL until all Generation Resources On-Line and interconnected at the same transmission bus are operating at their respective CURLs or URLs.

(5) ERCOT shall coordinate Automatic Voltage Regulator (AVR), dynamic and static reactive device Outages to ensure adequate reactive reserves are maintained.

(6) ERCOT shall maintain a performance log of QSE acknowledgements of VSS Dispatch Instructions.

(7) ERCOT shall be aware of the location of and availability of reactive power resources, including AVRs and Power System Stabilizers (PSSs), and shall monitor their statuses.

(8) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows.

(9) ERCOT shall, for each Generation Resource, telemeter the Real-Time desired Voltage Set Point and the TSP-designated Point of Interconnection Bus (POIB) kV measurement via Inter-Control Center Communications Protocol (ICCP) to the QSE representing that Generation Resource.

(10) ERCOT shall instruct the TO to make Voltage Set Point adjustments, as necessary, within the Generation Resource's URL provided to ERCOT.

[NOGRR204 and NOGRR212: Replace applicable portions of Section 2.7.3.2 above with the following upon system implementation of NPRR989 or NPRR1016, respectively:]

2.7.3.2 ERCOT Responsibilities

(1) ERCOT shall be responsible for ordering necessary Generation Resources or ESRs On-Line to regulate transmission voltage and reactive flow.

(2) When voltage levels deviate from normal operating limits in the pre-contingency (base case) condition or from emergency operating limits in the post-contingency condition, ERCOT shall take immediate steps to restore voltage levels within the applicable operating limits using all available reactive resources. ERCOT may allow additional time for a TO to correct the voltage levels to within limits on sub-100kV facilities prior to ERCOT taking further steps to restore voltage levels. The steps ERCOT may take include, but are not limited to:

(a) Evaluating TO actions taken to correct voltage levels;

(b) Directing additional Generation Resources or ESRs On-Line;

(c) Redispatching Generation Resources or ESRs;

(d) Deploying additional Resources;

(e) Directing static Reactive Power resources to be put in service;

(f) Utilizing temporary changes to limits of Resources or Transmission Facilities;

(g) Developing a Constraint Management Plan (CMP);

(h) Adjusting a Voltage Set Point; and

(i) Shedding firm Load.

(3) ERCOT shall issue a VSS Dispatch Instruction to the designated QSE for adjustments that would require a Generation Resource or ESR to operate outside its Unit Reactive Limit (URL).

(4) For multi-generator busses, ERCOT may not instruct any single Generation Resource or ESR to operate beyond its Corrected Unit Reactive Limit (CURL) or URL until all Generation Resources and/or ESRs On-Line and interconnected at the same transmission bus are operating at their respective CURLs or URLs.

(5) ERCOT shall coordinate Automatic Voltage Regulator (AVR), dynamic and static reactive device Outages to ensure adequate reactive reserves are maintained.

(6) ERCOT shall maintain a performance log of QSE acknowledgements of VSS Dispatch Instructions.

(7) ERCOT shall be aware of the location of and availability of reactive power resources, including AVRs and Power System Stabilizers (PSSs), and shall monitor their statuses.

(8) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows.

(9) ERCOT shall, for each Generation Resource and ESR providing VSS, telemeter the Real-Time desired Voltage Set Point and the TSP-designated Point of Interconnection Bus (POIB) kV measurement via Inter-Control Center Communications Protocol (ICCP) to the QSE representing that Generation Resource or ESR.

(10) ERCOT shall instruct the TO to make Voltage Set Point adjustments, as necessary, within the Generation Resource's or ESR's URL provided to ERCOT.

2.7.3.3 TO/TSP Responsibilities

(1) Each TO shall be responsible for directing Voltage Set Points for each Generation Resource interconnected to its TSP's Facilities. Each TO will adjust the Voltage Set Point by communicating directly with the Resource Entity or QSE responsible for the operation of the Generation Resource. Normal communication is to request voltage or Reactive Power be raised or lowered at a specified bus by a stated number of kV or MVAr (e.g., + 1 kV, +20 MVAr, or -1 kV, -20 MVAr).

(2) Each TO shall monitor system voltages and shall operate voltage control equipment, including, but not limited to, static Reactive Power resources such as capacitors, reactors and transformer tap changers to maintain system voltages within limits.

(3) Each TO shall operate static Reactive Power resources within its operating area as required by its criteria while maintaining dynamic reactive reserves, both leading and lagging, provided by Generation Resources. Except as reasonably necessary to ensure reliability or operational efficiency, TOs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource.

(4) Each TO shall telemeter to ERCOT via ICCP the Real-Time desired Voltage Set Point and actual voltage at the POIB for each Generation Resource interconnected to its system. Each TO shall modify the telemetered Voltage Set Point as soon as practicable in order to match any verbal Voltage Set Point instruction issued.

(5) Each TO shall know the status of static transmission Reactive Power resources in its operating area and shall provide such information to ERCOT.

(6) When voltage levels deviate from established limits, the affected TO shall take immediate steps to relieve the condition using available reactive resources under its control.

(7) Each TSP shall, as soon as practicable, notify ERCOT of any temporary transmission voltage limit changes and shall coordinate with ERCOT to update the Network Operations Model with any permanent or long-term changes to voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines.

[NOGRR177, NOGRR204, and NOGRR212: Replace applicable portions of Section 2.7.3.3 above with the following upon system implementation of NPRR857, NPRR989, or NPRR1016, respectively:]

2.7.3.3 TO/TSP/DCTO Responsibilities

(1) Each TO shall be responsible for directing Voltage Set Points for each Generation Resource and ESR required to provide VSS interconnected to its TSP's Facilities. Each TO will adjust the Voltage Set Point by communicating directly with the Resource Entity or QSE responsible for the operation of the Generation Resource or ESR. Normal communication is to request voltage or Reactive Power be raised or lowered at a specified bus by a stated number of kV or MVAr (e.g., + 1 kV, +20 MVAr, or -1 kV, -20 MVAr).

(2) Each TO shall monitor system voltages and shall operate voltage control equipment, including, but not limited to, static Reactive Power resources such as capacitors, reactors and transformer tap changers to maintain system voltages within limits.

(3) Each TO shall operate static Reactive Power resources within its operating area as required by its criteria while maintaining dynamic reactive reserves, both leading and lagging provided by Generation Resources and ESRs. Except as reasonably necessary to ensure reliability or operational efficiency, TOs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or

ESR.

(4) Each TO shall telemeter to ERCOT via ICCP the Real-Time desired Voltage Set Point and actual voltage at the POIB for each Generation Resource and ESR interconnected to its system required to provide VSS. Each TO shall modify the telemetered Voltage Set Point as soon as practicable in order to match any verbal Voltage Set Point instruction issued.

(5) Each TO shall know the status of static transmission Reactive Power resources in its operating area and shall provide such information to ERCOT.

(6) When voltage levels deviate from established limits, the affected TO shall take immediate steps to relieve the condition using available reactive resources under its control.

(7) Each TSP and DCTO shall, as soon as practicable, notify ERCOT of any temporary transmission voltage limit changes and shall coordinate with ERCOT to update the Network Operations Model with any permanent or long-term changes to voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines.

2.7.3.4 QSE Responsibilities

(1) Each QSE shall ensure that any Generation Resource that it represents and that is required to provide VSS responds to any VSS Dispatch Instruction including VSS Dispatch Instruction to exceed its CURL or URL or TO Voltage Set Point instruction within the time requirements specified in paragraph (3)(b) of Section 2.2.10, Generation Resource Response Time Requirements, even if the new Voltage Set Point is within the tolerance band identified in paragraph (4) of Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource Requirements. If the Resource Entity notifies the QSE that a Generation Resource cannot comply with the VSS Dispatch Instruction or TO Voltage Set Point instruction, either the Resource Entity or its QSE shall, as soon as practicable, notify the Entity that issued the instruction. The Resource Entity or its QSE shall provide the reason for not being able to comply and an estimated time for resolution, when known.

(2) Each QSE representing a Generation Resource shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement to the Generation Resource.

(3) Each QSE will continuously monitor the status of its Generating Resources' AVRs and PSSs.

(4) Each QSE must, as soon as practicable, notify ERCOT when a Generation Resource experiences a change that affects its reactive capability, including any change to the operation mode of the Generation Resource's AVR.

[NOGRR204: Replace Section 2.7.3.4 above with the following upon system implementation of NPRR989:]

2.7.3.4 QSE Responsibilities

(1) Each QSE shall ensure that any Generation Resource or ESR that it represents and that is required to provide VSS responds to any VSS Dispatch Instruction including VSS Dispatch Instruction to exceed its CURL or URL or TO Voltage Set Point instruction within the time requirements specified in paragraph (3)(b) of Section 2.2.10, Generation Resource and Energy Storage Resource Response Time Requirements, even if the new Voltage Set Point is within the tolerance band identified in paragraph (4) of Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements. If the Resource Entity notifies the QSE that a Generation Resource or an ESR cannot comply with the VSS Dispatch Instruction or TO Voltage Set Point instruction, either the Resource Entity or its QSE shall, as soon as practicable, notify the Entity that issued the instruction. The Resource Entity or its QSE shall provide the reason for not being able to comply and an estimated time for resolution, when known.

(2) Each QSE representing a Generation Resource or ESR shall provide in Real-Time the desired Voltage Set Point and the associated POIB kV measurement to the Generation Resource or ESR.

(3) Each QSE will continuously monitor the status of its Resources' AVRs and PSSs.

(4) Each QSE must, as soon as practicable, notify ERCOT when a Generation Resource or ESR experiences a change that affects its reactive capability, including any change to the operation mode of the Generation Resource's or ESR's AVR.

2.9.1 Additional Voltage Ride-Through Requirements for Intermittent Renewable Resources

(1) All Intermittent Renewable Resources (IRRs) shall also comply with the requirements of this Section, except as follows:

(a) An IRR that interconnects to the ERCOT System pursuant to a Standard Generation Interconnection Agreement (SGIA) (i) executed on or before January 16, 2014 and (ii) under which the IRR provided all required financial security to the TSP on or before January 16, 2014, is not required to meet any high VRT requirement greater than 1.1 per unit voltage unless the interconnected IRR includes one or more turbines that differ from the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014. Notwithstanding the foregoing, if the Resource Entity that owns or operates an IRR that was interconnected pursuant to an SGIA executed

before January 16, 2014, under which the IRR provided all required financial security to the TSP on or before January 16, 2014, demonstrates to ERCOT's satisfaction that the high VRT capability of the IRR is not lower than the capability of the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014 that IRR is not required to meet the high VRT requirement in this Section.

(b) An IRR that interconnects to the ERCOT System pursuant to an SGIA executed prior to November 1, 2008 is not required to meet VRT requirements presented in this Section. However, any WGR that is installed on or after November 1, 2008 and that initially synchronizes with the ERCOT System, pursuant to a Standard Generation Interconnection Agreement (SGIA) (i) executed on or before January 16, 2014, and (ii) under which the IRR provided all required financial security to the TSP on or before January 16, 2014 (except for an IRR installed pursuant to an SGIA executed before November 1, 2008) shall be VRT-capable in accordance with the low VRT requirements in this Section and high-voltage requirements in this Section up to 1.1 per unit voltage unless the interconnected IRR includes one or more turbines that differ from the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014 in which case the IRR shall also be required to comply with the high VRT requirements of this section, subject to the exemption described in paragraph (a), above.

(c) An IRR that is not technically capable of complying with a 1.2 per unit voltage high VRT requirement and that is not subject to either of the exemptions described in paragraphs (a) or (b), above, is not required to meet any high VRT requirement greater than 1.1 per unit voltage until January 16, 2016.

(d) Notwithstanding any of the foregoing provisions, an IRR's VRT capability shall not be reduced over time.

(2) Each IRR shall provide technical documentation of VRT capability to ERCOT upon request.

(3) Each IRR is required to set generator voltage relays to remain in service for at least 0.15 seconds during all transmission faults and to allow the system to recover as illustrated in Figure 1, Default Voltage Ride-Through Boundaries for IRRs, below. Recovery time to 90% of per unit voltage should be within 1.75 seconds. Faults on individual phases with delayed clearing (zone 2) may result in phase voltages outside this boundary but if the phase voltages remain inside this boundary, then generator voltage relays are required to be set to remain connected and recover as illustrated in Figure 1.

(4) Each IRR shall remain interconnected during three-phase faults on the ERCOT System for a voltage level as low as zero volts with a duration of 0.15 seconds as measured at the Point of Interconnection Bus (POIB) unless a shorter clearing time requirement for a three-phase fault specific to the generating plant POI is determined by and documented

by the TSP in conjunction with the SGIA. The clearing time requirement shall not exceed nine cycles.

(5) Each IRR shall set generator voltage relays to remain interconnected to the ERCOT System during the following high-voltage conditions, as illustrated in Figure 1: any per-unit voltage equal to or greater than 1.175 but less than 1.2 for up to 0.2 seconds, any per-unit voltage equal to or greater than 1.15 but less than 1.175 per unit voltage for up to 0.5 seconds, and any per-unit voltage equal to or greater than 1.1 but less than 1.15 for up to 1.0 seconds. The indicated voltages are measured at the POIB.

(6) An IRR may be tripped Off-Line or curtailed after the fault clearing period if this action is part of an approved Remedial Action Scheme (RAS).

(7) VRT requirements may be met by the performance of the generators; by installing additional reactive equipment behind the POI; or by a combination of generator performance and additional equipment behind the POI. VRT requirements may be met by equipment outside the POI if documented in the SGIA.

(8) If an IRR fails to comply with the clearing time or recovery VRT requirement, then the IRR and the interconnecting TSP shall be required to investigate and report to ERCOT on the cause of the IRR trip, identifying a reasonable mitigation plan and timeline.

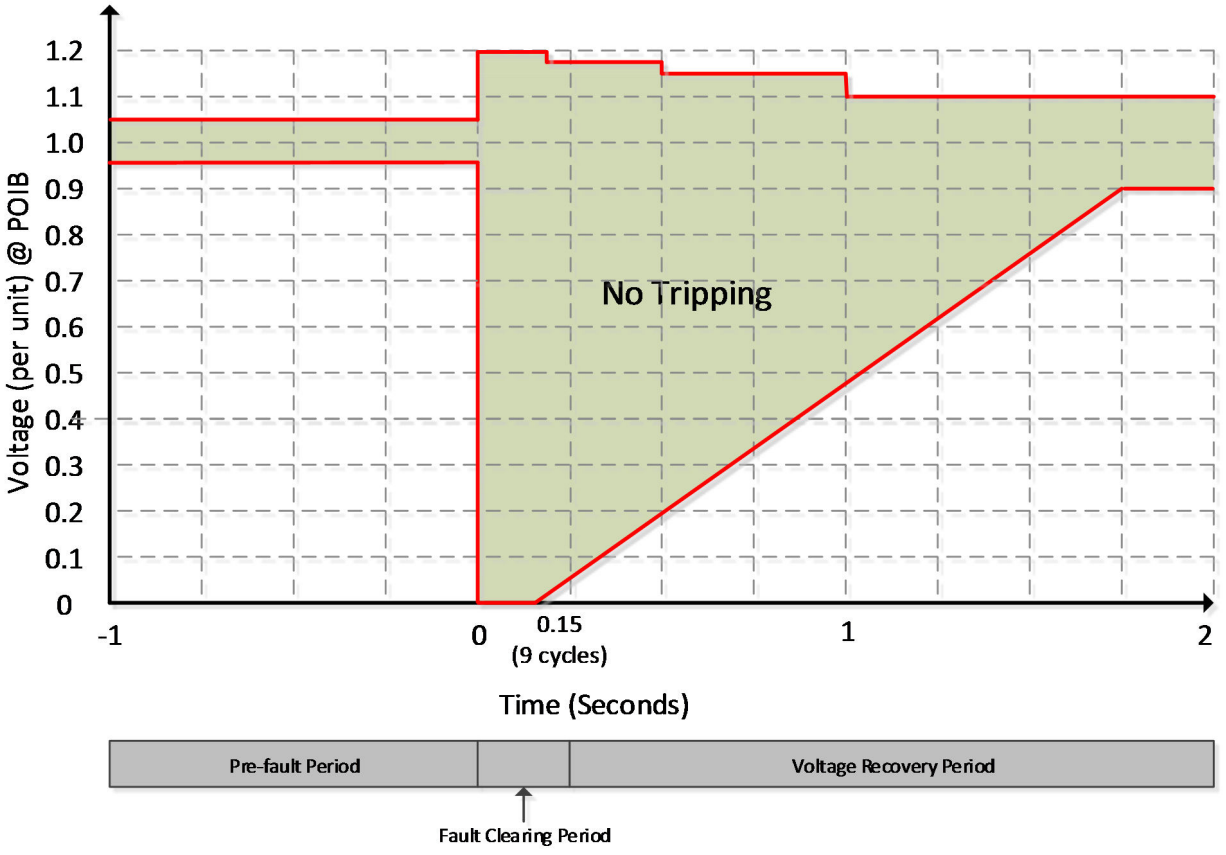


Figure 1: Default Voltage Ride-Through Boundaries for IRRs

[NOGRR204 and NOGRR212: Replace applicable portions of Section 2.9.1 above with the following upon system implementation of NPRR989 or NPRR1016, respectively:]

2.9.1 Voltage Ride-Through Requirements for Intermittent Renewable Resources and Energy Storage Resources Connected to the ERCOT Transmission Grid

(1) All Intermittent Renewable Resources (IRRs) and ESRs that interconnect to the ERCOT Transmission Grid shall also comply with the requirements of this Section, except as follows:

(a) An IRR that interconnects to the ERCOT Transmission Grid pursuant to a Standard Generation Interconnection Agreement (SGIA) (i) executed on or before January 16, 2014 and (ii) under which the IRR provided all required financial security to the TSP on or before January 16, 2014, is not required to meet any high VRT requirement greater than 1.1 per unit voltage unless the interconnected IRR includes one or more turbines that differ from the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014. Notwithstanding the foregoing, if the Resource Entity that owns or operates an IRR that was interconnected pursuant to an SGIA executed before January 16, 2014, under which the IRR provided all required financial

security to the TSP on or before January 16, 2014, demonstrates to ERCOT's satisfaction that the high VRT capability of the IRR is not lower than the capability of the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014 that IRR is not required to meet the high VRT requirement in this Section.

(b) An IRR that interconnects to the ERCOT System pursuant to an SGIA executed prior to November 1, 2008 is not required to meet VRT requirements presented in this Section. However, any WGR that is installed on or after November 1, 2008 and that initially synchronizes with the ERCOT System, pursuant to a Standard Generation Interconnection Agreement (SGIA) (i) executed on or before January 16, 2014, and (ii) under which the IRR provided all required financial security to the TSP on or before January 16, 2014 (except for an IRR installed pursuant to an SGIA executed before November 1, 2008) shall be VRT-capable in accordance with the low VRT requirements in this Section and high-voltage requirements in this Section up to 1.1 per unit voltage unless the interconnected IRR includes one or more turbines that differ from the turbine model(s) described in the SGIA (including any attachment thereto), as that agreement existed on January 16, 2014 in which case the IRR shall also be required to comply with the high VRT requirements of this section, subject to the exemption described in paragraph (a), above.

(c) An IRR that is not technically capable of complying with a 1.2 per unit voltage high VRT requirement and that is not subject to either of the exemptions described in paragraphs (a) or (b), above, is not required to meet any high VRT requirement greater than 1.1 per unit voltage until January 16, 2016.

(d) Notwithstanding any of the foregoing provisions, an IRR's VRT capability shall not be reduced over time.

(2) Each IRR or ESR shall provide technical documentation of VRT capability to ERCOT upon request.

(3) Each IRR or ESR is required to set its voltage relays to remain in service for at least 0.15 seconds during all transmission faults and to allow the system to recover as illustrated in Figure 1, Default Voltage Ride-Through Boundaries for IRRs and ESRs, below. Recovery time to 90% of per unit voltage should be within 1.75 seconds. Faults on individual phases with delayed clearing (zone 2) may result in phase voltages outside this boundary but if the phase voltages remain inside this boundary, then Resource voltage relays are required to be set to remain connected and recover as illustrated in Figure 1.

(4) Each IRR or ESR shall remain interconnected during three-phase faults on the ERCOT System for a voltage level as low as zero volts with a duration of 0.15 seconds as measured at the Point of Interconnection (POI) unless a shorter clearing time requirement for a three-phase fault specific to the POI is determined by and documented by the TSP in conjunction with the SGIA. The clearing time requirement shall not exceed nine

cycles.

(5) Each IRR or ESR shall set its voltage relays to remain interconnected to the ERCOT System during the following high-voltage conditions, as illustrated in Figure 1: any per-unit voltage equal to or greater than 1.175 but less than 1.2 for up to 0.2 seconds, any per-unit voltage equal to or greater than 1.15 but less than 1.175 per unit voltage for up to 0.5 seconds, and any per-unit voltage equal to or greater than 1.1 but less than 1.15 for up to 1.0 seconds. The indicated voltages are measured at the POI.

(6) An IRR or ESR may be tripped Off-Line or curtailed after the fault clearing period if this action is part of an approved Remedial Action Scheme (RAS).

(7) VRT requirements may be met by the performance of the Resource; by installing additional reactive equipment behind the POI; or by a combination of Resource performance and additional equipment behind the POI. VRT requirements may be met by equipment outside the POI if documented in the SGIA.

(8) If an IRR or ESR fails to comply with the clearing time or recovery VRT requirement, then the Resource Entity and the interconnecting TSP shall be required to investigate and report to ERCOT on the cause of the Resource's trip, identifying a reasonable mitigation plan and timeline.

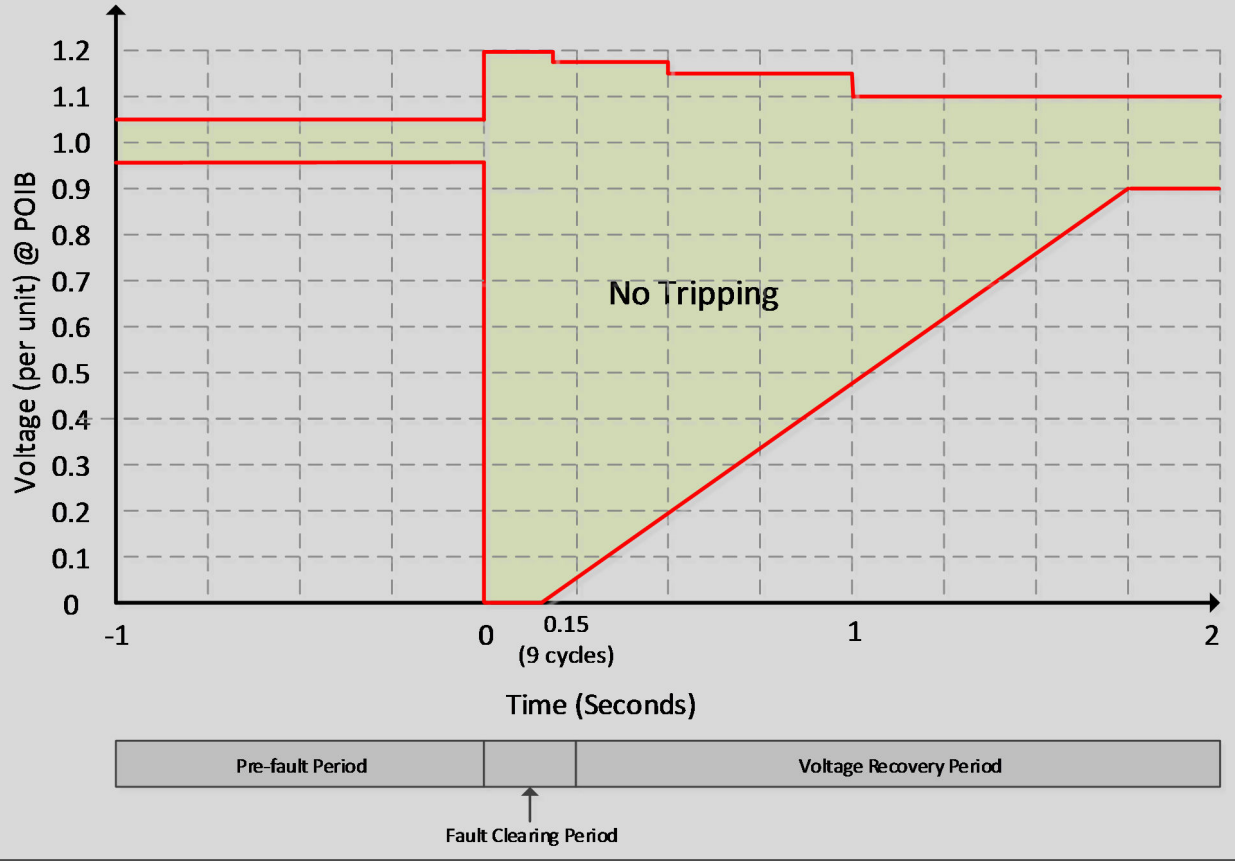


Figure 1: Default Voltage Ride-Through Boundaries for IRRs and ESRs Connected to the ERCOT Transmission Grid

3.3.2.1 Corrected Unit Reactive Limits (CURL)

(1) A reactive capability curve and associated data for each unit on the ERCOT System shall be submitted to ERCOT through the Market Information System (MIS) Certified Area and must contain the most limiting elements for the leading and lagging reactive output. The limiting factors such as under-excitation limiters, over-excitation limiters, ambient temperature limitations across the MW range of the unit at the unit terminals or any other factor that limits the reactive output of the unit and is verifiable through engineering calculations or testing shall be updated and provided on the corrected reactive capability curve. The corrected reactive capability curve establishes the Corrected Unit Reactive Limits (CURL) at the unit terminals that ERCOT Planning and ERCOT Operations, and TSPs will use for their studies. For Intermittent Renewable Resources (IRRs) the CURL data shall be reported at the low side of the generator step up transformer to the Point of Interconnection Bus (POIB). Resources will provide these updated curves and associated test data to ERCOT by submitting test information to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area. Once approved by ERCOT per Section 3.5, ERCOT Implementation, Resources will provide updated data by submitting changes to the appropriate ERCOT Resource Registration information in accordance with Planning Guide Section 6.8, Resource Registration Procedures. Prior to including the submitted data into the Network Operations Model, ERCOT will notify the TSP to which the Resource Entity is interconnected that the test data is posted on the MIS Secure Area. ERCOT and TSPs may review the data and provide any comments within ten Business Days. ERCOT will include these changes in the future Network Operations Model and forward the changes to the TSPs and the Steady State Working Group (SSWG) for use in their studies. The CURL should be available in the Resource Entities' control room where the tests are conducted and at the QSE's Real-Time generation dispatch desk. During any test, the Generation Resource must maintain its generator cooling system at normal operating conditions, the automatic voltage regulator in service and all auxiliary equipment in service that is needed for expected normal operation.

[NOGRR196: Replace Section 3.3.2.1 above with the following upon system implementation of NPRR973:]

3.3.2.1 Corrected Unit Reactive Limits (CURL)

(1) A reactive capability curve and associated data for each unit on the ERCOT System shall be submitted to ERCOT through the Market Information System (MIS) Certified Area and must contain the most limiting elements for the leading and lagging reactive output. The limiting factors such as under-excitation limiters, over-excitation limiters, ambient temperature limitations across the MW range of the unit at the unit terminals or any other factor that limits the reactive output of the unit and is verifiable through

engineering calculations or testing shall be updated and provided on the corrected reactive capability curve. The corrected reactive capability curve establishes the Corrected Unit Reactive Limits (CURL) at the unit terminals that ERCOT Planning and ERCOT Operations, and TSPs will use for their studies. For Intermittent Renewable Resources (IRRs) the CURL data shall be reported at the low side of the MPT. Resources will provide these updated curves and associated test data to ERCOT by submitting test information to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area. Once approved by ERCOT per Section 3.5, ERCOT Implementation, Resources will provide updated data by submitting changes to the appropriate ERCOT Resource Registration information in accordance with Planning Guide Section 6.8, Resource Registration Procedures. Prior to including the submitted data into the Network Operations Model, ERCOT will notify the TSP to which the Resource Entity is interconnected that the test data is posted on the MIS Secure Area. ERCOT and TSPs may review the data and provide any comments within ten Business Days. ERCOT will include these changes in the future Network Operations Model and forward the changes to the TSPs and the Steady State Working Group (SSWG) for use in their studies. The CURL should be available in the Resource Entities' control room where the tests are conducted and at the QSE's Real-Time generation dispatch desk. During any test, the Generation Resource must maintain its generator cooling system at normal operating conditions, the automatic voltage regulator in service and all auxiliary equipment in service that is needed for expected normal operation.

[NOGRR204: Replace Section 3.3.2.1 above with the following upon system implementation of NPRR989:]

3.3.2.1 Corrected Unit Reactive Limits (CURL)

(1) A reactive capability curve and associated data for each unit on the ERCOT System shall be submitted to ERCOT through the Market Information System (MIS) Certified Area and must contain the most limiting elements for the leading and lagging reactive output. The limiting factors such as under-excitation limiters, over-excitation limiters, ambient temperature limitations across the MW range of the unit at the unit terminals or any other factor that limits the reactive output of the unit and is verifiable through engineering calculations or testing shall be updated and provided on the corrected reactive capability curve. The corrected reactive capability curve establishes the Corrected Unit Reactive Limits (CURL) at the unit terminals that ERCOT Planning and ERCOT Operations, and TSPs will use for their studies. For Intermittent Renewable Resources (IRRs) and Energy Storage Resources (ESRs) the CURL data shall be reported at the low side of the unit's step up transformer to the Point of Interconnection Bus (POIB). Resources will provide these updated curves and associated test data to ERCOT by submitting test information to the Net Dependable Capability and Reactive Capability (NDCRC) application located on the MIS Secure Area. Once approved by ERCOT per Section 3.5, ERCOT Implementation, Resources will provide updated data by submitting changes to the appropriate ERCOT Resource Registration information in

accordance with Planning Guide Section 6.8, Resource Registration Procedures. Prior to including the submitted data into the Network Operations Model, ERCOT will notify the TSP to which the Resource Entity is interconnected that the test data is posted on the MIS Secure Area. ERCOT and TSPs may review the data and provide any comments within ten Business Days. ERCOT will include these changes in the future Network Operations Model and forward the changes to the TSPs and the Steady State Working Group (SSWG) for use in their studies. The CURL should be available in the Resource Entity's control room where the tests are conducted and at the QSE's Real-Time Resource dispatch desk. During any test, the Generation Resource or ESR must maintain its cooling system at normal operating conditions, the Automatic Voltage Regulator in service and all auxiliary equipment in service that is needed for expected normal operation.

3.3.2.2 Reactive Testing Requirements

(1) Reactive testing may be performed as either "Coordinated," or "Non-Coordinated," the difference being the amount of notification provided to ERCOT and the TO, and level of their involvement in testing.

(a) Coordinated Testing

(i) Coordinated testing is the preferred method for new or larger-capacity units, as it provides a greater amount of coordination with ERCOT and the TO, allowing testing impacts and any potential adjustments to local voltage levels to be studied in advance.

(ii) The Resource Entity requesting a Coordinated test must submit a test request to ERCOT and the TO via their QSE, by no later than 15:00, one day prior to the proposed test date. ERCOT and the TO then have until 17:00 of the day prior to the proposed test date, to either approve or disapprove the test request.

(iii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(iv) The test requests should contain the proposed time and date of the test, type of test (leading or lagging), expected unit MW and MVAr output range during the test, and a copy of the reactive capability curve.

(b) Non-Coordinated Testing

(i) The Resource Entity representing the resource requesting a Non-Coordinated test must inform ERCOT and the TO via their QSE at least two hours prior to the proposed start of the test.

(ii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(2) Lagging Reactive Testing

(a) It is recommended, but not required, that lagging reactive tests be performed when system voltage is within the voltage profile, such as during high load periods.

(b) Lagging tests should meet the following performance criteria:

(i) Lagging Test 1: Test at or above 95% of the unit's High Sustained Limit (HSL) for at least 15 minutes. IRRs should test at or above 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Lagging Test 2: Test at the unit's HSL for at least one hour. IRRs should test with at least 90% of photovoltaic inverters or wind turbines on-line. Testing acceptance criteria is met if the unit achieved at least 50% of the units CURL for one hour.

(iii) Lagging Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(3) Leading Reactive Testing

(a) It is recommended, but not required, that leading reactive tests be performed when system voltage is within the voltage profile, such as during low load periods.

(b) Leading tests should meet the following performance criteria:

(i) Leading Test 1: Test at the unit's normally expected maximum real power output during system light load conditions for at least 15 minutes. IRRs should test at or below 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's original manufacturer reactive curve or most recent CURL.

(ii) Leading Test 2: Test at the unit's HSL for at least one minute. IRR units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(iii) Leading Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(4) The Resource Entity shall measure the tested reactive capability on the generator output terminals for non-IRR Generation Resources. The value recorded shall represent the gross MVAr output of the Generation Resource. Additionally, the net reactive capability shall be measured at the high side of the GSU transformer and at the POIB, if metering is available. The high side values shall have the Generation Resource's auxiliary reactive consumption and the GSU losses deducted from the Generation Resource's gross reactive output. The POIB values shall have the plant's auxiliary load and any additional load deducted from the Generation Resource's gross reactive output. If metering is not available at the high side, the Resource Entity shall calculate the reactive capability at the high side and at the POIB. These values are required and must be submitted through the MIS Certified Area. CURLs shall be attached to the test results submitted, and shall be clearly defined. All applicable test data shall be submitted on the form in the NDCRC application.

(5) The QSE representing a Generation Resource shall be responsible for scheduling reactive verification tests when requested by the Resource Entity in accordance with the conditions outlined above. If ERCOT does not issue a specific request for a Generation Resource reactive capability verification, the Generation Resource shall complete a reactive verification test at least every five years.

(6) ERCOT shall have the option to waive the requirement to perform Leading Test 1 for any Generation Resource that seldom runs during such light Load periods. The granting of such a waiver shall be effective for five years.

(7) The Resource Entity representing a Generation Resource shall be responsible for the timely and accurate reporting of test results to ERCOT and to the QSE representing the Generation Resource. The Resource Entity representing a Generation Resource must properly complete all required data fields in the NDCRC application for a test to be considered valid.

[NOGRR204: Replace Section 3.3.2.2 above with the following upon system implementation of NPRR989:]

3.3.2.2 Reactive Testing Requirements

(1) Reactive testing may be performed as either "Coordinated," or "Non-Coordinated," the difference being the amount of notification provided to ERCOT and the TO, and level of their involvement in testing.

(a) Coordinated Testing

(i) Coordinated testing is the preferred method for new or larger-capacity units, as it provides a greater amount of coordination with ERCOT and the TO, allowing testing impacts and any potential adjustments to local voltage levels to be studied in advance.

(ii) The Resource Entity requesting a Coordinated test must submit a test request to ERCOT and the TO via their QSE, by no later than 15:00, one

day prior to the proposed test date. ERCOT and the TO then have until 17:00 of the day prior to the proposed test date, to either approve or disapprove the test request.

(iii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(iv) The test requests should contain the proposed time and date of the test, type of test (leading or lagging), expected unit MW and MVAr output range during the test, and a copy of the reactive capability curve.

(b) Non-Coordinated Testing

(i) The Resource Entity representing the resource requesting a Non-Coordinated test must inform ERCOT and the TO via their QSE at least two hours prior to the proposed start of the test.

(ii) Both ERCOT and the TO have the right to deny or cancel a test at any time, if they feel that system reliability may be adversely impacted by the test.

(2) Lagging Reactive Testing

(a) It is recommended, but not required, that lagging reactive tests be performed when system voltage is within the voltage profile, such as during high load periods.

(b) For Generation Resources, lagging tests should meet the following performance criteria:

(i) Lagging Test 1: Test at or above 95% of the unit's High Sustained Limit (HSL) for at least 15 minutes. IRRs should test at or above 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Lagging Test 2: Test at the unit's HSL for at least one hour. IRRs should test with at least 90% of photovoltaic inverters or wind turbines on-line. Testing acceptance criteria is met if the unit achieved at least 50% of the units CURL for one hour.

(iii) Lagging Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs, ESRs, and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(c) For inverter-based ESRs, lagging tests should meet the following performance

criteria:

(i) Lagging Test 1a: Test at or above 95% the unit's Maximum Operating Discharge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Lagging Test 1b: Test at or above 95% of the unit's Maximum Operating Charge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(iii) Lagging Test 2: Test with at least 90% of the ESR's inverters On-Line for at least one hour. Testing acceptance criteria is met if the unit achieved at least 50% of its CURL for 1 hour at any MW level.

(3) Leading Reactive Testing

(a) It is recommended, but not required, that leading reactive tests be performed when system voltage is within the voltage profile, such as during low load periods.

(b) For Generation Resources, leading tests should meet the following performance criteria:

(i) Leading Test 1: Test at the unit's normally expected maximum real power output during system light load conditions for at least 15 minutes. IRRs should test at or below 60% of their HSL. Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's original manufacturer reactive curve or most recent CURL.

(ii) Leading Test 2: Test at the unit's HSL for at least one minute. IRR units and ESRs are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(iii) Leading Test 3: Test at the unit's normally expected minimum real power output during system light load conditions for at least one minute. IRRs and nuclear units are exempt from this test. Testing acceptance criteria is met if the unit achieved at least 50% of the unit's CURL.

(c) For ESRs leading tests should meet the following performance criteria:

(i) Leading Test 1a: Test at or above 95% of the unit's Maximum Operating Discharge Power Limit for at least 15 minutes or entire

duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(ii) Leading Test 1b: Test at or above 95% of the unit's Maximum Operating Charge Power Limit for at least 15 minutes or entire duration if less than 15 minutes.

Testing acceptance criteria is met if the unit achieved no less than 90% of the unit's most recent CURL.

(4) The Resource Entity shall measure the tested reactive capability on the generator output terminals for non-IRR Generation Resources. The value recorded shall represent the gross MVAr output of the Generation Resource or ESR. Additionally, the net reactive capability shall be measured at the high side of the GSU transformer and at the POIB, if metering is available. The high side values shall have the Generation Resource's or ESR's auxiliary reactive consumption and the GSU losses deducted from the Generation Resource's or ESR's gross reactive output. The POIB values shall have the plant's auxiliary load and any additional load deducted from the Resource's gross reactive output. If metering is not available at the high side, the Resource Entity shall calculate the reactive capability at the high side and at the POIB. These values are required and must be submitted through the MIS Certified Area. CURLs shall be attached to the test results submitted, and shall be clearly defined. All applicable test data shall be submitted on the form in the NDCRC application.

(5) The QSE representing a Generation Resource or ESR shall be responsible for scheduling reactive verification tests when requested by the Resource Entity in accordance with the conditions outlined above. If ERCOT does not issue a specific request for a Generation Resource or ESR reactive capability verification, the Generation Resource or ESR shall complete a reactive verification test at least every five years.

(6) ERCOT shall have the option to waive the requirement to perform Leading Test 1 for any Generation Resource or ESR that seldom runs during such light Load periods. The granting of such a waiver shall be effective for five years.

(7) The Resource Entity representing a Generation Resource or ESR shall be responsible for the timely and accurate reporting of test results to ERCOT and to the QSE representing the Generation Resource or ESR. The Resource Entity representing a Generation Resource or ESR must properly complete all required data fields in the NDCRC application for a test to be considered valid.

ERCOT Nodal Operating Guides
Section 8
Attachment C

Turbine Governor Speed Tests

TBD

TURBINE GOVERNOR SPEED REGULATION TEST FOR MECHANICAL-HYDRAULIC GOVERNOR

GENERAL INFORMATION

Unit Code (16 characters): _____Location (County):_____

Unit Name: _____Date of test: _____

QSE:_____Resource Entity: _____

Steady State Speed Regulation at High-Speed Stop

$$Rs = \frac{(A - B) \times 100}{3600}$$

Where:

A = Speed with speed changer set at high-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

B = Speed with speed changer set at high-speed stop and when governing valves just reach wide-open position.

Steady State Speed Regulation at Synchronous Speed [1]

$$Rs = \frac{(C - D) \times 100}{3600}$$

Where:

C = Speed with speed changer set for synchronous speed and with throttle (or stop) valves open and machine running idle on the Governor.

D = Speed with speed changer set at the same position as in C above and when governing valves just reach wide open position.

Steady State Speed Regulation at Low-Speed Stop

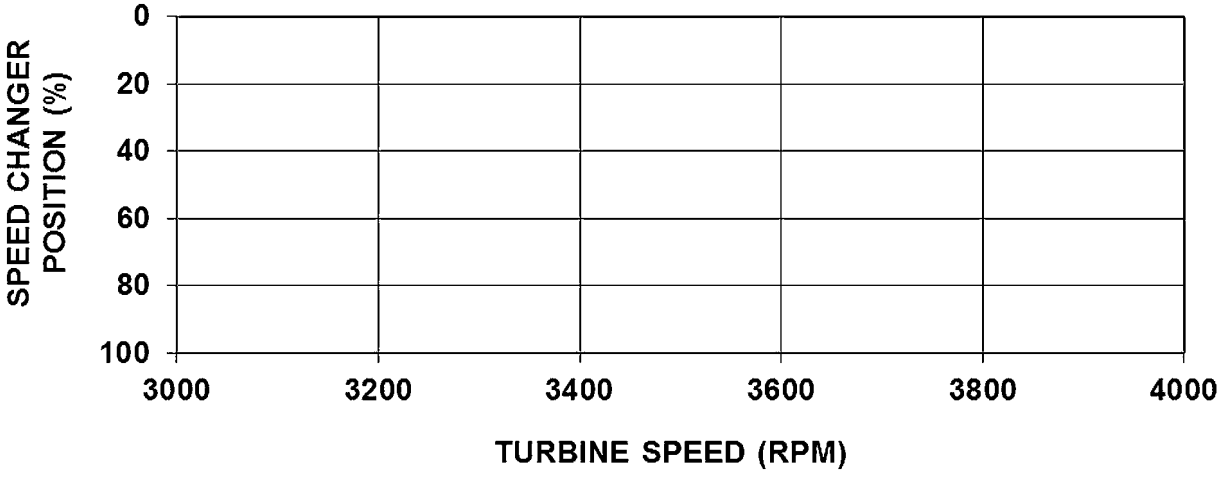
$$Rs = \frac{(E - F) \times 100}{3600}$$

[1] Westinghouse recommends using only this test.

Where:

E = Speed with speed changer set at low-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

F = Speed with speed changer set at low-speed stop and when governing valves just reach wide-open position.



E, F @ Low Speed Stop
C, D @ Sync. Speed
A, B @ High Speed Stop

Test Data

Point	A	B	C	D	E	F
Speed, RPM						
Frequency Hz						

Speed Changer Travel Time:

(a) From Low-Speed Stop to High-Speed Stop in _____seconds.
(b) From High-Speed Stop to Low-Speed Stop in _____seconds.

Over-speed Trip Test Speed at _____rpm.

Comments:_____
_____
_____
_____
_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Representative: _____

EXAMPLE OF A TURBINE GOVERNOR SPEED REGULATION TEST FOR MECHANICAL-HYDRAULIC GOVERNOR

Steady State Speed Regulation at High-Speed Stop

$$Rs = \frac{(A-B)\times 100}{3600} = \frac{(3850-3570)\times 100}{3600} = 7.78\%$$

Where:

A = Speed with speed changer set at high-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

B = Speed with speed changer set at high-speed stop and when governing valves just reach wide-open position.

Steady State Speed Regulation at Synchronous Speed [2]

$$Rs = \frac{(C-D)\times 100}{3600} = \frac{(3600-3310)\times 100}{3600} = 8.06\%$$

Where:

C = Speed with speed changer set for synchronous speed and with throttle (or stop) valves open and machine running idle on the Governor.

D = Speed with speed changer set at the same position as in C above and when governing valves just reach wide open position.

Steady State Speed Regulation at Low-Speed Stop

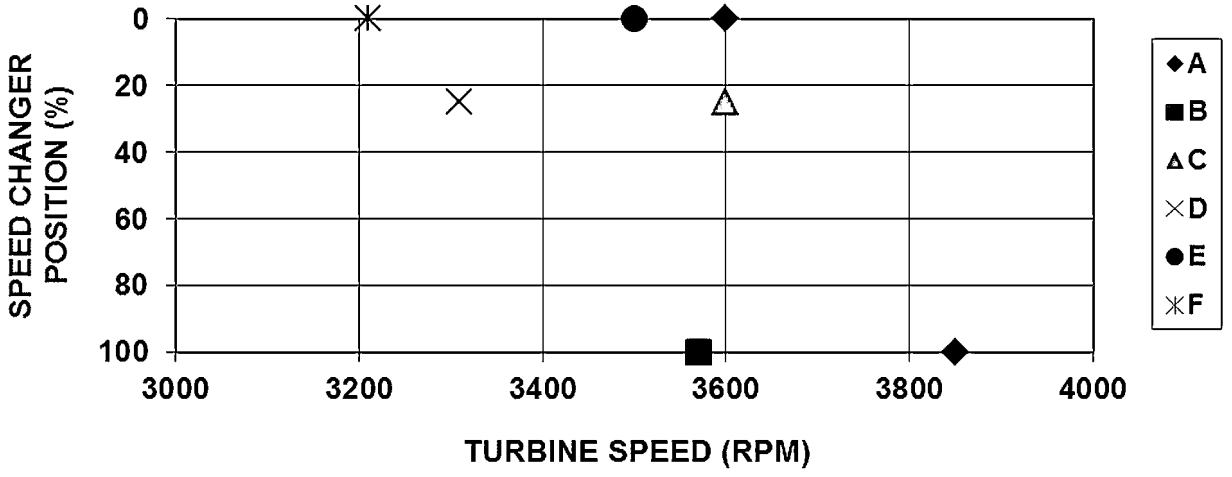
$$Rs = \frac{(E-F)\times 100}{3600} = \frac{(3500-3210)\times 100}{3600} = 8.06\%$$

Where:

[2] Westinghouse recommends using only this test.

E = Speed with speed changer set at low-speed stop and with throttle (or stop) valves open and machine running idle on the Governor.

F = Speed with speed changer set at low-speed stop and when governing valves just reach wide-open position.



E, F @ Low Speed Stop
C, D @ Sync. Speed
A, B @ High Speed Stop

Test Data

Point	A	B	C	D	E	F
Speed, RPM	3850	3570	3600	3310	3500	3210
Frequency Hz	64.2	59.5	60.0	55.0	58.3	53.5

Speed Changer Travel Time:

(a) From low-speed stop to high-speed stop in 73 seconds.

(b) From high-speed stop to low-speed stop in 74 seconds.

Over-speed trip test speed at 3965 rpm.

Comments: _____

_____

_____

_____

TURBINE GOVERNOR SPEED REGULATION TEST FOR ELECTRO-HYDRAULIC GOVERNOR

GENERAL INFORMATION

Unit Code (16 characters): _____ Location (County):_____

Unit Name: _____ Date of test: _____

QSE:_____ Resource Entity: _____

Turbine Governor Speed Regulation Test Procedures

(a) Simulate unit On-Line and turbine speed at 3600 RPM.

(b) Set Load reference at minimum value.

(c) Monitor valve demand signal and record as value "A" (in %).

(d) Reduce speed until valve demand just reaches maximum value. Record valve demand as value "B" (in %) and speed as value "C" (in RPM).

(e) Set speed at 3600 and Load reference at maximum value.

(f) Monitor valve demand signal and record as value "D" (in %).

(g) Increase speed until valve demand just reaches minimum value. Record valve demand as value "E" (in %) and speed as value "F" (in RPM).

Turbine Governor Speed Regulation Test Results

	A	B	C	D	E	F
Valve Demand (%)						
Speed (rpm)						

Speed Regulation With Decreasing Speed

$$R_D = \frac{100}{(B - A)} \times \frac{(3600 - C)}{3600} \times 100$$

Speed Regulation With Increasing Speed

$$R_I = \frac{100}{(D-E)} \times \frac{(F-3600)}{3600} \times 100$$

Comments: _____

_____

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Representative: _____

DEFINITIONS

System Frequency Response	This response is a function of two key variables: the Primary Frequency Response from Governors and Load dampening of the connected Load.
Percent Droop Settings	Also known as Frequency Regulation, Speed Regulation, Speed Sensitivity, Speed Error and others. Percent droop is the percent change in nominal frequency that will cause generator output to change from no Load to full Load. It is the change in steady state rotor speed, expressed in percent of rated speed, when power output is gradually reduced from rated to zero power. A common percent droop setting is 5% for both high and low frequency excursions.
Dead-Band	The range of deviations of system frequency (+/-) that produces no turbine Governor response, and therefore, no frequency (speed) regulation. It is expressed in percent of rated speed, Hz, or RPM.

NOGRR204: Replace "Percent Droop Settings" and "Dead-Band" above with the following upon system implementation of NPRR989:]

Percent Droop Settings	Also known as Frequency Regulation, Speed Regulation, Speed Sensitivity, Speed Error and others. Percent droop is the percent change in nominal frequency that will cause generator output to change from no Load to full Load. For synchronous Resources, it is the change in steady state rotor speed, expressed in percent of rated speed, when power output is gradually reduced from rated to zero power. A common percent droop setting is 5% for both high and low frequency excursions.
Dead-Band	The range of deviations of system frequency (+/-) that produces no Governor response, and therefore, no frequency (speed) regulation. It is expressed in percent of rated speed, Hz, or RPM.

Valve Position Limiter	A device that acts on the speed and Load governing system to prevent the Governor-controlled valves from opening beyond a pre-set limit.
Blocked Governor Operation	Operating the generating unit with the control system adjusted to prevent the turbine governor from responding to system frequency (speed) variations. In an effort to reduce speed Governor operation in some generating units, turbine control systems can be adjusted to block the operation of the Governor after the unit is in parallel with the system and is running at its desired output. Selection of a high percent

droop characteristic or a large Governor Dead-Band constitutes a form of blocked Governor action.

Variable Pressure Operation

Varying the boiler pressure to improve turbine efficiency at lower Loads. Two methods are normally used. The first method, the turbine control (G.E.) or Governor (Westinghouse) valves are positioned in the wide-open position and the generator is changed by changing the boiler pressure. With this method, there is very little, if any response to frequency excursions. The second method, the valves are positioned at approximately 50% open. The valves are still able to respond to system disturbances. Normal changes in generation requirements are made by varying the boiler pressure until the unit is at rated pressure. After full pressure is reached, the turbine valves are used to make the required generation changes.

2 Generation Resource Frequency Response Test Procedure

DESCRIPTION OF THE TEST

1. The frequency response function of the Generation Resource is tested On-Line at a Load level that allows the Generation Resource to increase or decrease Load without reaching low operating limits or high operating limits. If the Generation Resource cannot be tested On-Line then it will notify ERCOT that it will be conducting an Off-Line test. The recommended level is 92% Base Load or below.

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create immediate step change in the measured frequency signal.

3. The test starts at time t0 when the frequency Dead-Band is exceeded and signal "Generation Resource Frequency Response On" becomes active.

4. The following signals should be recorded at least two seconds: Unit MW Output, "Generation Resource Frequency Response On."

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the Generation Resource should return to pretest power output.

6. The test should be conducted both with positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

DEFINITIONS

Generation Resource Base Load = maximum Load capability for the season when frequency response test is performed

$$\textbf{Gain MW for 0.1Hz} = \frac{P}{(Droop * 60 - GovernorDead - Band) * 10}$$

Where:

P = Generation Resource Base Load (MW)

$Droop$ = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz (+12 rpm and -12 rpm, for 3600 sync speed machines), outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz *10*Frequency Offset

Calculated droop = $-\frac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = Generation Resource Base Load (MW)

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power output (MW)

EXAMPLE

Generation Resource Base Load = 150 MW

Droop = 0.05 or 5% (use 0.05 for calculation)

Governor Dead-Band = 0.034

Gain MW to 0.1 Hz = $\frac{150}{[(0.05 * 60) - 0.034] * 10}$ = +/- 5.06 MW/0.1 Hz

MW Contribution = 5.06*10*+/- (0.2) = +/-10.12 MW

Expected under-frequency response: +10.12 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response: -10.12 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response: +7.08 MW in 15 sec. for -0.2 Hz offset
Minimum accepted over-frequency response: -7.08 MW in 15 sec. for +0.2 Hz offset

Calculated droop for 8 MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated droop = $-\frac{150 * -0.2}{60 * 8}$ = 0.0625 or 6.25%

GENERATION RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): _____Location (County): _____

Unit Name: _____Date of Test:_____

QSE: _____Resource Entity: _____

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	Generation Resource Base Load		
2	GAIN MW to 0.1Hz		
3	Calculated MW Contribution		
4	MW at test start (t_0)		
5	MW at t_0 + 16 sec		
6	MW Contribution at t_0 + 16 sec		
7	MW at t_0 + 46 sec		
8	Calculated droop		
9	CONCLUSION (PASSED/FAILED)		

Comments:

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____.

Date submitted to ERCOT Representative: _____

[NOGRR204: Insert item "Energy Storage Resource Frequency Response Test Procedure" and "Energy Storage Resource Frequency Response Test Form" below upon system implementation of NPRR989:]

ENERGY STORAGE RESOURCE FREQUENCY RESPONSE TEST PROCEDURE

DESCRIPTION OF THE TEST

1. An Energy Storage Resource (ESR) is tested On-Line in both maximum charging and discharging modes at a level that allows the ESR to increase or decrease Load without reaching its operating limits. If the ESR cannot be tested On-Line then it will notify ERCOT that it will be conducting an Off-Line test.

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create an immediate step-change in the measured frequency signal.

3. The test starts at time t0 when the frequency dead-band is exceeded.

4. The following signals should be recorded for at least two seconds: unit MW level and frequency offset signal.

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the Energy Storage Resource should return to the pretest MW level.

6. The test should be conducted with both positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7, Turbine Speed Governors.

DEFINITIONS

Energy Storage Resource Base Load = for low frequency test maximum charging capability; for high frequency test maximum discharging capability

Gain MW for 0.1Hz = $$\frac{P}{(Droop * 60 - GovernorDead - Band) * 10}$$

Where:

P = Energy Storage Resource Base Load (MW)

Droop = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz (+12 rpm and -12 rpm, for 3600 sync speed machines), outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz *10*Frequency Offset

Calculated droop = $- \frac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = Energy Storage Resource Base Load (MW)

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power level (MW)

EXAMPLE

Energy Storage Resource Base Load = 150 MW, when discharging

Droop = 0.05 or 5% (use 0.05 for calculation)

Governor Dead-Band = 0.017

Gain MW to 0.1 Hz = $\frac{150}{[(0.05 * 60) - 0.017] * 10}$ = +/- 5.03 MW/0.1 Hz

MW Contribution (injection) = 5.03*10*+/- (0.2) = +/-10.06 MW

Expected under-frequency response (injection): +10.06 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response (withdrawal): -10.06 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response (injection): +7.04 MW in 15 sec. for -0.2 Hz offset
Minimum accepted over-frequency response (withdrawal): -7.04 MW in 15 sec. for +0.2 Hz offset

Calculated droop for 8 MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated droop = $-\frac{150 * -0.2}{60 * 8}$ = 0.0625 or 6.25%

ENERGY STORAGE RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): _____ Location (County): _____

Unit Name: _____ Date of Test: _____

QSE: _____ Resource Entity: _____

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	Energy Storage Resource (ESR) Base Load		
2	GAIN MW to 0.1Hz		
3	Calculated MW Contribution		
4	MW at test start (t_0)		
5	MW at t_0 + 16 sec		
6	MW Contribution at t_0 + 16 sec		
7	MW at t_0 + 46 sec		
8	Calculated droop		
9	CONCLUSION (PASSED/FAILED)		

Comments:

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Representative: _____

GENERATION RESOURCE AND CONTROLLABLE LOAD RESOURCE PRIMARY FREQUENCY RESPONSE TEST PROCEDURES BASED ON HISTORICAL DATA

DESCRIPTION OF HISTORICAL VERIFICATION

The purpose of this template is to allow the Entity that operates a Generation Resource or a Controllable Load Resource to demonstrate acceptable frequency response of its Generation Resource(s) or Controllable Load Resource(s) based on historical data in order to minimize testing costs, scheduling conflicts and the risk of damage to equipment or Forced Outage.

1. All verifications will be based on at least one of the events from the published list of Frequency Measurable Events (FMEs).

2. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7. For Controllable Load Resources, Governor droop shall not exceed 5% and Governor Dead-Band shall not exceed +/-0.036Hz.

3. For clarification purposes, the time of FME (t(0)), pre-perturbation average frequency and post-perturbation average frequency, as defined in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response, will be used for the verification process. The values of these metrics will be identified in the FME Report.

4. The test is considered successful if the Generation Resource or the Controllable Load Resource is able to meet a minimum of 75% of its initial Primary Frequency Response and 75% of its sustained Primary Frequency Response as calculated in the FMEs report posted on the Market Information System (MIS) Certified Area. Any Generation Resource or Controllable Load Resource may use the FME report in lieu of testing.

    a. The calculation of Generation Resources or Controllable Load Resources initial and sustained Primary Frequency Response is detailed in Section 8, Attachment J.

    b. ERCOT shall evaluate initial and sustained Primary Frequency Response using an expected performance Governor droop of 5.78% for combined-cycle Resources.

5. Intermittent Renewable Resources (IRRs) located behind one Point Of Interconnection (POI), metered by one ERCOT-Polled Settlement (EPS) Meter, and operated as an integrated Facility may combine IRRs for the purposes of this test.

DEFINITIONS

Generation Resource or Controllable Load Resource Base Load = maximum rated capability (this value is not reduced for temporary output limitations of the Generation Resource or Controllable Load Resource due to auxiliary equipment outages, weather conditions, or fuel limitations, it is the "nameplate" rating of the Generation Resource or Controllable Load Resource). For the IRR, the Base Load for purposes of this test shall be the Real-Time telemetered High Sustained Limit (HSL) (MW) of the IRR at the time of the FME. The IRR shall use only a FME in which the IRR's HSL is greater than 50% of the IRR's total design output capability.

3 HISTORICAL GENERATION RESOURCE OR CONTROLLABLE LOAD RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): Location (County):

Unit Name: Date of FME:

QSE: Resource Entity:

HISTORICAL RESULTS

EVALUATION POINT	*FREQUENCY*
TIME (SEC) OF FME (T(0))	
PRE-PERTURBATION AVERAGE FREQUENCY (T(-2) TO T(-16))	
POST-PERTURBATION AVERAGE FREQUENCY (T(20) TO T(52))	

1	**Pre-Perturbation Average MW [T(-2) to T(-16)]**	
2	**Post-Perturbation Average MW [T(+20 to T(+52)]**	
3	**Expected Initial Primary Frequency Response (MW)**	
4	**Expected Sustained Primary Frequency Response (MW)**	
5	**Adjusted Actual Initial Primary Frequency Response (MW)**	
6	**Adjusted Actual Sustained Primary Frequency Response (MW)**	
7	**Initial Response P.U. Performance**	

8	**Sustained Response P.U. Performance**	

Comments:

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Representative: _____

[NOGRR204: Replace "Generation Resource and Controllable Load Resource Primary Frequency Response Test Procedures Based on Historical Data" and "Generation Resource and Controllable Load Resource Frequency Response Test Form" with the following upon system implementation of NPRR989:]

GENERATION RESOURCE, ENERGY STORAGE RESOURCE, AND CONTROLLABLE LOAD RESOURCE PRIMARY FREQUENCY RESPONSE TEST PROCEDURES BASED ON HISTORICAL DATA

DESCRIPTION OF HISTORICAL VERIFICATION

The purpose of this template is to allow the Entity that operates a Generation Resource, Energy Storage Resource (ESR), or a Controllable Load Resource to demonstrate acceptable frequency response of its Generation Resource(s), ESR(s), or Controllable Load Resource(s) based on historical data in order to minimize testing costs, scheduling conflicts and the risk of damage to equipment or Forced Outage.

1. All verifications will be based on at least one of the events from the published list of Frequency Measurable Events (FMEs).

2. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7.

3. For clarification purposes, the time of FME (t(0)), pre-perturbation average frequency and post-perturbation average frequency, as defined in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response, will be used for the verification process. The values of these metrics will be identified in the FME Report.

4. The test is considered successful if the Generation Resource, ESR, or the

Controllable Load Resource is able to meet a minimum of 75% of its initial Primary Frequency Response and 75% of its sustained Primary Frequency Response as calculated in the FMEs report posted on the Market Information System (MIS) Certified Area. Any Generation Resource, ESR, or Controllable Load Resource may use the FME report in lieu of testing.

a. The calculation of Generation Resources, ESRs, or Controllable Load Resources initial and sustained Primary Frequency Response is detailed in Section 8, Attachment J.

b. ERCOT shall evaluate initial and sustained Primary Frequency Response using an expected performance Governor droop of 5.78% for combined-cycle Resources.

5. Intermittent Renewable Resources (IRRs) located behind one Point of Interconnection (POI), metered by one ERCOT-Polled Settlement (EPS) Meter, and operated as an integrated Facility may combine IRRs for the purposes of this test.

DEFINITIONS

Generation Resource, ESR, or Controllable Load Resource Base Load = maximum rated capability (this value is not reduced for temporary output limitations of the Generation Resource, ESR, or Controllable Load Resource due to auxiliary equipment outages, weather conditions, or fuel limitations, it is the "nameplate" rating of the Generation Resource, ESR, or Controllable Load Resource). For the IRR, the Base Load for purposes of this test shall be the Real-Time telemetered High Sustained Limit (HSL) (MW) of the IRR at the time of the FME. The IRR shall use only a FME in which the IRR's HSL is greater than 50% of the IRR's total design output capability.

4

5 HISTORICAL GENERATION RESOURCE, ENERGY STORAGE RESOURCE, OR CONTROLLABLE LOAD RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters):	Location (County):
Unit Name:	Date of FME:
QSE:	Resource Entity:

HISTORICAL RESULTS

EVALUATION POINT	*FREQUENCY*

TIME (SEC) OF FME (T(0))	
PRE-PERTURBATION AVERAGE FREQUENCY (T(-2) TO T(-16))	
POST-PERTURBATION AVERAGE FREQUENCY (T(20) TO T(52))	

1	**Pre-Perturbation Average MW [T(-2) to T(-16)]**	
2	**Post-Perturbation Average MW [T(+20 to T(+52)]**	
3	**Expected Initial Primary Frequency Response (MW)**	
4	**Expected Sustained Primary Frequency Response (MW)**	
5	**Adjusted Actual Initial Primary Frequency Response (MW)**	
6	**Adjusted Actual Sustained Primary Frequency Response (MW)**	
7	**Initial Response P.U. Performance**	
8	**Sustained Response P.U. Performance**	

Comments:

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Representative: _____

INTERMITTENT RENEWABLE RESOURCE (IRR) FREQUENCY RESPONSE TEST PROCEDURE

DESCRIPTION OF THE TEST

1. The frequency response function of the Intermittent Renewable Resource (IRR) is tested On-Line at a Load level that allows the IRRs to increase or decrease Load without reaching low operating limits or high operating limits.

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create immediate step change in the measured frequency signal.

3. The test starts at time t0 when the frequency Dead-Band is exceeded.

4. The MW output signal should be recorded at least every two seconds.

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the IRR should return to pretest power output.

6. The test should be conducted both with positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7.

9. IRRs located behind one POI, metered by one ERCOT-Polled Settlement (EPS) Meter, and operated as an integrated Facility may combine IRRs for the purposes of this test.

DEFINITIONS

IRR Base Load = IRR telemetered High Sustained Limit (HSL) at the time of the test. The test shall be performed at an output level which is greater than 50% of IRR's total design output capability.

Gain MW for 0.1Hz consistent with a selected droop percentage =

$$\frac{P * 10}{Droop * 60 - GovernorDe\,ad - Band}$$

Where:

P = IRR telemetered HSL (MW)

Droop = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz, outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz * 10 * Frequency Offset

Calculated droop = $-\frac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = IRR telemetered HSL (MW)

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power output (MW)

EXAMPLE

IRR telemetered HSL = 150 MW

Droop = 0.05 or 5% (use 0.05 for calculation)

Governor Dead-Band = 0.017 Hz

Gain MW for 0.1 Hz = $\frac{150}{[(0.05 * 60) - 0.017] * 10}$ = +/- 5.03 MW/0.1 Hz

ΔMW Contribution = 5.03 * 10* +/-0.2 = +/-10.06 MW

Expected under-frequency response: +10.06 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response: -10.06 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response: +7.04 MW in 16 sec. for -0.2 Hz offset
Minimum accepted over-frequency response: -7.04 MW in 16 sec. for +0.2 Hz offset

Calculated droop for 8MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated percent droop = $-\frac{150 * -0.2}{60 * 8}$ *100 = 6.25%

INTERMITTENT RENEWABLE RESOURCE (IRR) FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): _____Location (County): _____

Unit Name: _____Date of Test:_____

QSE: _____Resource Entity: _____

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	IRR Base Load		
2	GAIN MW to 0.1Hz		
3	Calculated Minimum MW Contribution		
4	MW at test start (t_0)		
5	MW at t_0 + 16 sec		
6	MW Contribution at t_0 + 16 sec		
7	MW at t_0 + 46 sec		
8	Calculated droop		
9	CONCLUSION (PASSED/FAILED)		

Comments:

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Control Area Authority Rep.: _____

6 Controllable load resource Frequency Response Test Procedure

DESCRIPTION OF THE TEST

1. The frequency response function of the Controllable Load Resource is tested On-Line at a Load level that allows Controllable Load Resources to increase or decrease Load without reaching Low Power Consumption (LPC) or Maximum Power Consumption (MPC).

2. The test is performed by adding a frequency offset signal that exceeds the Governor Dead-Band value to the measured frequency signal. This should create an immediate step change in the measured frequency signal.

3. The test starts at time t0 when the frequency Dead-Band is exceeded.

4. The MW output signal should be recorded at least every two seconds.

5. The duration of the test is 100 seconds. After 100 seconds, the offset signal should be removed and the Controllable Load Resource should return to pretest power output.

6. The test should be conducted both with positive and negative frequency offsets.

7. The test is considered successful after the signal becomes active if at least 70% of the calculated MW contribution is delivered within 16 seconds and the response is maintained for an additional 30 seconds.

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7. For Controllable Load Resources, Governor droop shall not exceed 5% and Governor Dead-Band shall not exceed +/-0.036Hz.

[NOGRR204: Replace item (8) above with the following upon system implementation of NPRR989:]

8. Governor droop and Governor Dead-Band settings shall be set in accordance with Section 2.2.7.

DEFINITIONS

Controllable Load Resource Base Load = Controllable Load Resource telemetered MPC at the time of the test. The test shall be performed at an output level that allows the Controllable Load Resource to increase or decrease Load without reaching LPC or MPC.

Gain MW for 0.1Hz consistent with a selected droop percentage =

$$\frac{P}{(Droop * 60 - GovernorDe\,ad - Band) * 10}$$

Where:

P = Controllable Load Resource telemetered MPC (MW)

Droop = droop (%)

Frequency Offset = +0.2 Hz and -0.2 Hz, outside Governor Dead-Band

Test frequency = Measured Frequency + Frequency Offset

MW Contribution = Gain MW to 0.1 Hz * 10 * Frequency Offset

Calculated droop = $- \frac{P * \Delta Hz}{60 * \Delta MW}$

Where:

P = Controllable Load Resource telemetered MPC

ΔHz = Change in frequency (Hz), taking into account Governor Dead-Band

ΔMW = Change in power output (MW)

EXAMPLE

Controllable Load Resource telemetered MPC = 150 MW

Droop = 5%

Governor Dead-Band = 0.036 Hz

Gain MW to 0.1 Hz = $\frac{150}{[(0.05 * 60) - 0.036] * 10}$ = +/- 5.06 MW/0.1 Hz

ΔMW Contribution = 5 * 10* +/-0.2 = +/-10.12 MW

Expected under-frequency response: -10.12 MW in 16 sec. for -0.2 Hz offset
Expected over-frequency response: +10.12 MW in 16 sec. for +0.2 Hz offset

Minimum accepted under-frequency response: -7.08 MW in 16 sec. for -0.2 Hz offset
Minimum accepted over-frequency response: +7.08 MW in 16 sec. for +0.2 Hz offset

Note: The negative sign in expected under-frequency response and minimum accepted under-frequency response denotes the required reduction in power consumption.

Similarly the positive sign in expected over-frequency response and minimum accepted over-frequency response denotes the required increase in power consumption.

Calculated droop for 8 MW increase in power output in 16 sec. for -0.2 Hz offset:

Calculated percent droop = $-\frac{150 * -0.2}{60 * 8} = 6.25\%$

CONTROLLABLE LOAD RESOURCE FREQUENCY RESPONSE TEST FORM

GENERAL INFORMATION

Unit Code (16 characters): _____Location (County): _____

Unit Name: _____Date of Test:_____

QSE: _____Resource Entity: _____

TEST RESULTS

		Test with +0.2 Hz	Test with -0.2 Hz
1	Controllable Load Resource Base Load		
2	GAIN MW to 0.1 Hz		
3	Calculated Minimum MW Contribution		
4	MW at test start (t_0)		
5	MW at t_0 + 16 sec		
6	MW Contribution at t_0 + 16 sec		
7	MW at t_0 + 46 sec		
8	Calculated droop		
9	CONCLUSION (PASSED/FAILED)		

Comments:

_____

_____

_____

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Control Area Authority Rep.:_____

ERCOT Operating Guides
Section 8
Attachment D

Seasonal Unit Net Real Power Capability Verification

TBD

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7 Seasonal Unit Net Real Power Capability Verification

GENERAL INFORMATION

Unit Code (16 character): _____ Location (County): _____

Unit Name: _____ Date of test: _____

Generator's QSE: _____ Resource Entity: _____

TEST RESULTS

Start Time: _____

Start MW (Gross)*: _____

Start MW (Net)**: _____

MW 10 Minutes after Start Time (Gross)*: _____

MW 10 Minutes after Start Time (Net)**: _____

Time to Reach Maximum Generation: _____

Temperature at Plant (°F): _____

MW at Maximum Generation (Gross)*: _____

MW at Maximum Generation (Net)**: _____

MWH Net during the First Full Clock Hour after Maximum Generation is reached: _____

Limiting Factors: _____

* Value measured at generator terminals
** Value measured at the Point Of Interconnection Bus (POIB)

SUBMITTAL

Resource Entity Representative: _____

QSE Representative: _____

Date submitted to ERCOT Rep.: _____

ERCOT Impact Analysis Report

NOGRR Number	210	NOGRR Title	Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB)
Impact Analysis Date		February 26, 2020	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB).	
ERCOT Staffing Impacts (across all areas)		Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1005.

Alignment Nodal Operating Guide Revision Request

NOGRR Number	229	NOGRR Title	Alignment Changes for September 1, 2021 Nodal Operating Guide – NPRR995
Date Posted		August 10, 2021	
Status		Alignment Change	

Nodal Operating Guide Sections Requiring Revision	4.5.3.3, EEA Levels
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns Energy Emergency Alert (EEA) language in Section 4.5.3.3 with Protocol Section 6.5.9.4.2, EEA Levels. On August 10, 2021, the ERCOT Board approved NPRR995, which modified language in Protocol Section 6.5.9.4.2. Paragraph (6) of Section 1.3.1, Introduction, provides that ERCOT may make changes to the Nodal Operating Guide to maintain duplicate language between the Protocols and Nodal Operating Guide, and requires that Section 4.5.3.3 be modified only by an Alignment NOGRR.
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☒ Other: Alignment NOGRR *(please select all that apply)*
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR229 and believes the market impact for NOGRR229 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.

Sponsor	
Name	Phillip Bracy
E-mail Address	phillip.bracy@ercot.com

Alignment Nodal Operating Guide Revision Request

Company	ERCOT
Phone Number	512-248-6917
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	phillip.bracy@ercot.com
Phone Number	512-248-6917

Proposed Guide Language Revision

4.5.3.3 EEA Levels

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,300 MW and is not projected to be recovered above 2,300 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 1,750 MW:

(i) Request available Generation Resources, that can perform within the expected timeframe of the emergency, to come On-Line by initiating manual HRUC or through Dispatch Instructions;

(ii) Use available DC Tie import capacity that is not already being used;

(iii) Issue a Dispatch Instruction for Resources to remain On-Line which, before start of emergency, were scheduled to come Off-Line; and

(iv) At ERCOT's discretion, deploy available contracted Emergency Response Service (ERS)-30 via an Extensible Markup Language (XML) message followed by a Verbal Dispatch Instruction (VDI) to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been deployed. The ERS-30 ramp period shall begin at the completion of the VDI.

(A) If less than 500 MW of ERS-30 is available for deployment, ERCOT shall deploy it as a single block.

(B) If the amount of ERS-30 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-30 as a single block or by group designation. ERCOT shall develop a

random selection methodology for determining how to place ERS Resources in ERS-30 into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS Contract Period for ERS-30, ERCOT shall notify QSEs representing ERS Resources in ERS-30 of their ERS Resources' group assignments.

(C) ERS-30 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct their ERS Resources in ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT releases the ERS-30 deployment or the ERS-30 Resources have reached their maximum deployment time.

(E) ERCOT shall notify QSEs of the release of ERS-30 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been recalled. The VDI shall represent the official notice of ERS-30 release. ERCOT may release ERS-30 as a block or by group designation.

(F) Upon release, an ERS Resource in ERS-30 shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the release.

[NOGRR221: Insert item (v) below upon system implementation of NPRR1010:]

(v) At ERCOT's discretion, manually deploy, through Inter-Control Center Communications Protocol (ICCP), available RRS and ERCOT Contingency Reserve Service (ECRS) capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

(i) Ensure COPs and telemetered High Sustained Limits (HSLs) are updated and reflect all Resource delays and limitations; and

[NOGRR221: Replace paragraph (i) above with the following upon system implementation of NPRR1010:]

(i) Ensure COPs and telemetered HSLs, Normal Ramp Rates, Emergency Ramp Rates, and Ancillary Service capabilities are updated and reflect all

Resource delays and limitations; and

(ii) Suspend any ongoing ERCOT-required Resource performance testing.

[NOGRR216 and NOGRR229: Insert applicable portions of paragraph (iii) below upon system implementation of NPRR1010 for NOGRR216; or upon system implementation of NPRR995 for NOGRR229:]

(iii) Ensure that each of its ESRs and Settlement Only Energy Storage Systems (SOESSs) suspends charging until the EEA is recalled, except under the following circumstances:

(A) The ESR has a current SCED Base Point Instruction, Load Frequency Control Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;

(B) The ESR or SOESS is actively providing Primary Frequency Response; or

(C) The ESR or SOESS is co-located behind a Point of Interconnection (POI) with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained.

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 1,750 MW and is not projected to be recovered above 1,750 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,430 MW:

(i) Instruct TSPs and Distribution Service Providers (DSPs) or their agents to reduce Customer Load by using distribution voltage reduction measures, if deemed beneficial by the TSP, DSP or their agents;

(ii) Instruct TSPs and DSPs to implement any available Load management plans to reduce Customer Load;

(iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30 and/or deploy RRS supplied from Load Resources

(controlled by high-set under-frequency relays). ERCOT may deploy ERS-10, ERS-30 or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

[NOGRR186: Replace paragraph (iii) above with the following upon system implementation of NPRR863:]

(iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30, and/or deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ERS-10, ERS-30, ECRS, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

(iv) ERCOT shall deploy ERS-10 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been deployed. The ERS-10 ramp period shall begin at the completion of the VDI.

(A) If less than 500 MW of ERS-10 is available for deployment, ERCOT shall deploy all ERS-10 Resources as a single block.

(B) If the amount of ERS-10 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-10 Resources as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS-10 Resources into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS-10 Contract Period, ERCOT shall notify QSEs representing ERS-10 Resources of their ERS-10 Resources' group assignments.

(C) ERS-10 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct ERS-10 Resources to perform at contracted levels consistent with the criteria described in Protocol Section 8.1.3.1.4 until ERCOT releases the ERS-10 deployment or the ERS-10 Resources have reached their maximum deployment times.

(E) ERCOT shall notify QSEs of the release of ERS-10 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been recalled. The VDI shall represent the official notice of ERS-10 release. ERCOT may release ERS-10 as a block or by group designation.

(F) Upon release, an ERS-10 Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the release.

(v) ERCOT shall deploy RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

[NOGRR186: Replace paragraph (v) above with the following upon system implementation of NPRR863:]

(v) Load Resources providing ECRS that are not controlled by high set under-frequency relays shall be deployed prior to Group 1 deployment. ERCOT shall deploy ECRS and RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

(A) Instruct QSEs to deploy half of the RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 1 Load Resources providing RRS. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from Group 2 if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

[NOGRR186 and NOGRR198: Replace applicable portions of paragraph (A) above with the following upon system implementation of NPRR863 or NPRR939, respectively:]

(A) Instruct QSEs to deploy RRS with a Group 1 designation and all of the ECRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resources to interrupt Group 1 Load Resources providing ECRS and RRS. QSEs shall deploy Load Resources according to the group designation and will be

given some discretion to deploy additional Load Resources from any of the groups not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy the remaining RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 2 Load Resources providing RRS. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

[NOGRR198: Replace paragraph (B) above with the following upon system implementation of NPRR939:]

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt additional Load Resources providing RRS based on their group designation. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

(C) The ERCOT Operator may deploy both of the groups of Load Resources providing RRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; and

[NOGRR186 and NOGRR198: Replace applicable portions of paragraph (C) above with the following upon system implementation of NPRR863 or NPRR939, respectively:]

(C) The ERCOT Operator may deploy Load Resources providing only ECRS (not controlled by high-set under-frequency relays) and all groups of Load Resources providing RRS and ECRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute

deployment period; and

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the Day-Ahead Reliability Unit Commitment (DRUC) for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A), Group 1 and paragraph (B), Group 2. ERCOT shall develop a process for determining which individual Load Resource to place in Group 1 and which to place in Group 2. ERCOT procedures shall select Group 1 and Group 2 based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

[NOGRR198 and NOGRR221: Replace applicable portions of paragraph (D) above with the following upon system implementation of NPRR939 or NPRR1010, respectively:]

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource RRS or ECRS award, which may be deployed to interrupt under paragraph (A) and paragraph (B). ERCOT shall develop a process for determining which individual Load Resource to place in each group based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

(vi) Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation; and

(vii) With the approval of the affected non-ERCOT Control Area, TSPs, DSPs, or their agents may implement transmission voltage level BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas in accordance with BLTs as defined in the Operating Guides.

(b) Confidentiality requirements regarding transmission operations and system capacity information will be lifted, as needed to restore reliability.

(3) ERCOT may declare an EEA Level 3 when the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,430 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT will implement any measures associated with EEA Levels 1 and 2 that have not already been implemented.

[NOGRR216 and NOGRR229: Insert applicable portions of paragraph (a) below upon

system implementation of NPRR1002 and renumber accordingly for NOGRR216; or upon system implementation of NPRR995 for NOGRR229:]

(a) ERCOT shall instruct ESRs and SOESSs to suspend charging. For ESRs, ERCOT shall issue the instruction via a SCED Base Point, or, if otherwise necessary, via a manual Dispatch instruction. An ESR or SOESS shall suspend charging unless providing Primary Frequency Response or LFC issues a charging instruction to an ESR that is carrying Regulation Down Service (Reg-Down). However, an ESR or SOESS co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained.

(a) When PRC falls below 1,000 MW and is not projected to be recovered above 1,000 MW within 30 minutes, or when the clock-minute average frequency falls below 59.91 Hz for 25 consecutive minutes, ERCOT shall direct all TSPs and DSPs or their agents to shed firm Load, in 100 MW blocks, distributed as documented in these Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,000 MW of PRC within 30 minutes.

(b) In addition to measures associated with EEA Levels 1 and 2, TSPs and DSPs or their agents will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TSPs and DSPs or their agents shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

Board Report

PGRR Number	089	PGRR Title	Planning Data and Information Updates for Planning Posting
Date of Decision		August 10, 2021	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not applicable	
Planning Guide Sections Requiring Revision		7.1, Planning Data and Information	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Planning Guide Revision Request (PGRR) makes changes to the list of data sets posted to the Market Information System (MIS) in Section 7.1. First, it removes the Planning Horizon Transmission Capability Methodology from the list. Second, it adds Long-Term System Assessment (LTSA) postings, Geomagnetic Disturbance (GMD) vulnerability assessments, and the monthly Generator Interconnection Status (GIS) Report to the list.	
Reason for Revision		☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☒ Administrative ☐ Regulatory requirements ☒ Other: Retirement of North American Electric Reliability Corporation (NERC) Reliability Standard FAC-013-2, Assessment of Transfer Capability for the Near-term Transmission Planning Horizon *(please select all that apply)*	
Business Case		On December 14, 2020, NERC Reliability Standard FAC-013-2 was retired. As a result of the retirement, the Planning Horizon Transmission Capability Methodology became obsolete, and the	

	reference in the list should be removed from the Planning Guide. Additionally, ERCOT needs the option to post cases containing Protected Information used for the LTSA to the MIS Certified Area for Transmission Service Providers (TSPs), post material containing Protected Information for the GMD vulnerability assessments to the MIS Certified Area for TSPs, and post study results for the GMD vulnerability assessments to the MIS Secure Area. Finally, ERCOT started posting the monthly GIS reports to the ERCOT website in June 2020, so listing this report in the list recognizes the current posting procedure for this data set.
ROS Decision	On 4/1/21, ROS voted unanimously via roll call to table PGRR089 and refer the issue to Planning Working Group (PLWG). All Market Segments participated in the vote. On 4/29/21, ROS voted unanimously via roll call to recommend approval of PGRR089 as revised by ROS. All Market Segments participated in the vote. On 6/3/21, ROS voted unanimously via roll call to endorse and forward to TAC the 4/29/21 ROS Report and the Impact Analysis for PGRR089. All Market Segments participated in the vote.
Summary of ROS Discussion	On 4/1/21, the sponsors provided an overview of PGRR089. On 4/29/21, participants corrected an acronym in the list in Section 7.1. On 6/3/21, there was no discussion.
TAC Decision	On 6/23/21, TAC voted unanimously via roll call to recommend approval of PGRR089 as recommended by ROS in the 6/3/21 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/23/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of PGRR089.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR089 and believes the market impact for PGRR089 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board recommended approval of PGRR089 as recommended by TAC in the 6/23/21 TAC Report and the Revised Impact Analysis.

Board Report

Sponsor	
Name	Sun Wook Kang, John Bernecker, and Pete Warnken
E-mail Address	SunWook.Kang@ercot.com, John.Bernecker@ercot.com, Pete.Warnken@ercot.com
Company	ERCOT
Phone Number	512-248-4159
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	Phillip.Bracy@ercot.com
Phone Number	512-248-6917

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

7.1 Planning Data and Information

(1) The information available on the ERCOT website or applicable Market Information System (MIS) (i.e., Secure or Certified Areas) includes, but is not limited to, planning information pertaining to the following:

(a) Long-term planning;

(b) Regional transmission planning;

(c) Steady state data;

(d) Resource integration;

(e) Case studies and files used in planning;

(f) Model information; and

(g) Data and information available to specific groups of Market Participants.

(i) Market Participants with a nondisclosure agreement with ERCOT have designated sections on the MIS that allow access to the certified posting of group information.

(ii) Market Participants may access the artifacts posted for their respective groups on the MIS Secure Area.

(2) The list below includes both data set and designated MIS classification of the available planning data and information. Where the information is classified as "Certified," the appropriate Market Participant category or group is also indicated. Information classified as "Public" is available on the ERCOT website.

Data Set	**Classification**
Aggregated Wind Output	Public
Annual Planning Model Data Submittal Schedule	Secure
Demand and Energy Monthly Reports	Secure
Dynamic Data Information	Certified (all Transmission Service Providers (TSPs))
Economic Studies of Transmission Projects for New Generation	Secure
ERCOT Long-Term System Assessment (LTSA) (except for Protected Information)	Secure
ERCOT LTSA	Certified (all TSPs)
ERCOT Steady State Planning Contingency Files	Secure
ERCOT System Operating Limit (SOL) Methodology	Public
Generation Data Forms	Secure
Generator Interconnection Status (GIS) Report	Public
Geomagnetically-Induced Current (GIC) Flow Information	Secure
Geomagnetic Disturbance (GMD) Vulnerability Assessment Postings (except for Protected Information)	Secure
GMD Vulnerability Assessment Postings	Certified (all TSPs)
Documents Initiating a Generation Interconnection or Change Request (GINR)	Certified (all TSPs)
GINR Security Screening Studies and Supporting Documents	Secure

Sub-Synchronous Oscillation Studies and Supporting Documents	Certified (all TSPs)
Full Interconnection Study (FIS): Steady-State, System Protection, Stability, and Facility Studies and Supporting Documents (except for Protected Information)	Secure
FIS: Draft Steady-State, System Protection, Stability, and Facility Studies and Supporting Documents	Certified (all TSPs)
Independent Market Monitor (IMM) and Topology Processor Supporting Documents	Certified (all TSPs)
Performance, Disturbance, Compliance Working Group (PDCWG) Group Documents and Project Files	Certified (PDCWG members)
Public Generation Information	Public
Remedial Action Plan (RAP) Review Cases	Certified (all TSPs)
Resource Registration Data	Certified (all TSPs)
Regional Planning Group Projects	Secure
Regional Transmission Plan Postings (except for Protected Information)	Secure
Regional Transmission Plan Postings	Certified (all TSPs)
Seasonal Voltage Profile Studies	Certified (all TSPs)
Special Planning Studies (except for Protected Information)	Secure
Special Planning Studies	Certified (all TSPs)
Steady State Power Flow Base Cases	Secure
Steady State Power Flow Case Data	Certified (all TSPs)
Steady State Topology Processor Files	Secure
Steady State Transmission Project and Information Tracking (TPIT) Procedures	Secure
System Protection Short Circuit Data	Secure
Transient Stability Screening Study for ERCOT System	Certified (all TSPs)
TSP Planning Criteria and Procedures	Secure
Voltage Stability Screening Study for ERCOT System	Certified (all TSPs)

Revised ERCOT Impact Analysis Report

PGRR Number	089	PGRR Title	Planning Data and Information Updates for Planning Posting
Impact Analysis Date		July 27, 2021	
Estimated Cost/Budgetary Impact		Less than $5k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.	
Estimated Time Requirements		No project required. This Planning Guide Revision Request (PGRR) can take effect within 1-2 months after Public Utility Commission of Texas (PUCT) approval.	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • External Public 50% • Data Access & Transparency 50%	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this PGRR.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

Board Report

PGRR Number	091	PGRR Title	FIS Application Completion 60-Day Limit
Date of Decision		August 10, 2021	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		September 1, 2021	
Priority and Rank Assigned		Priority – 2022; Rank – 3530 (for automation)	
Planning Guide Sections Requiring Revision		5.3, Full Interconnection Study Request 5.4.2, Full Interconnection Study	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Planning Guide Revision Request (PGRR) establishes a limit for Interconnecting Entities (IEs) to complete an application to request a Full Interconnection Study (FIS) within 60 days of submittal. An FIS will be considered not to have been requested if the application is not completed within 60 days.	
Reason for Revision		☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*	
Business Case		Data extracted from Resource Integration and Ongoing Operations Interconnection Services (RIOO-IS) from January 1, 2020 to March 11, 2021 shows that 78% of FIS requests are completed within 60 days. Section 5.3 lists several items that an IE is required to submit for ERCOT to approve an FIS request. Under present rules, if an FIS has been requested but the application	

	is incomplete, and the requesting IE is not able to complete the application within 60 days, the associated Generation Interconnection or Change Request (GINR) would not be subject to cancellation for failure to timely request an FIS. See paragraph (5) of Section 5.4.1, Security Screening Study. The IE should be ready with all the required items prior to submitting an FIS request and should not be making an FIS request just to avoid being cancelled for not making the FIS request within 180 days of receiving the screening study results. RIOO-IS shows 22% of FIS requests since January 1, 2020 have exceeded 60 days with 26 GINRs exceeding 100 days. Depending on when the FIS request is made, cancelling the FIS request may result in the GINR being cancelled due to violation of the 180-day limit in paragraph (5) of Section 5.4.1.
ROS Decision	On 6/3/21, ROS voted unanimously via roll call to recommend approval of PGRR091 as revised by ROS. All Market Segments participated in the vote. On 7/8/21, ROS voted unanimously via roll call to endorse and forward to TAC the 6/3/21 ROS Report and the Impact Analysis for PGRR091 with a recommended priority of 2022 and rank of 3530. All Market Segments participated in the vote.
Summary of ROS Discussion	On 6/3/21, participants considered an additional provision for ERCOT to provide a 10-day notice of pending expiration of the 60-day limit. On 7/8/21, there was no discussion.
TAC Decision	On 7/28/21, TAC voted unanimously via roll call to recommend approval of PGRR091 as recommended by ROS in the 7/8/21 ROS Report; and the Revised Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/28/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of PGRR091.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR091 and believes the market impact for PGRR091 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.
Board Decision	On 8/10/21, the ERCOT Board recommended approval of PGRR091 as recommended by TAC in the 7/28/21 TAC Report.

Board Report

Sponsor	
Name	James Teixeira
E-mail Address	Jay.teixeira@ercot.com
Company	ERCOT
Phone Number	512-248-6582
Cell Number	512-656-6734
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	Phillip.Bracy@ercot.com
Phone Number	512-248-6917

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

5.3 Full Interconnection Study Request

(1) Any Interconnecting Entity (IE) seeking a Full Interconnection Study (FIS) for interconnection to the ERCOT System must submit the following to ERCOT:

(a) A change request via the online Resource Integration and Ongoing Operations (RIOO) system requesting to proceed with the FIS;

(b) Resource Registration data in the format prescribed by ERCOT with applicable information required for interconnection studies with the exception of the stability study as identified in the Resource Registration Glossary;

(c) A Full Interconnection Study Application Fee as prescribed in Section 5.7.3, Generation Interconnection and Full Interconnection Study Application Fee;

(d) Proof of site control as described in Section 5.4.9, Proof of Site Control; and

(e) A declaration in Section 8, Attachment C, Declaration of Department of Defense Notification, certifying that:

(i) The IE has notified the Department of Defense (DOD) Siting Clearinghouse of the proposed Generation Resource and requested an informal or formal review as described in 32 C.F.R. § 211.1 (2013); or

(ii) The IE's proposed Generation Resource is not required to provide notice to the DOD and Federal Aviation Administration (FAA) because the project does not meet the criteria requiring notice to the FAA under 14 C.F.R. § 77.9 (2010).

(2) Transmission Service Providers (TSPs) may charge additional fees for their interconnection studies.

(3) All FIS requests and supporting data submissions shall be entered via the online RIOO system. If any of the items required pursuant to paragraph (1) above are deemed not acceptable by ERCOT or are not submitted, then the IE must submit any omitted items and resolve and resubmit any deficient items. If the FIS request is not deemed complete by ERCOT within 60 days of submission of the FIS request, the FIS will be considered to have not been requested for the purpose of meeting paragraph (5) of Section 5.4.1, Security Screening Study. If the 180-day limit specified in paragraph (5) of Section 5.4.1 has expired, the Generation or Interconnection Change Request (GINR) will be cancelled immediately. If the 180-day limit has not expired and the deficiency is not resolved before the 180-day limit, the GINR will be cancelled upon expiration of the 180-day limit. ERCOT will provide a 10-day notification prior to expiration of the 60-day limit.

(4) The ERCOT designated point of contact will initiate an FIS study scope meeting between the TSP(s) and the IE. If during the course of the studies, additional information is needed by ERCOT from the IE, ERCOT will return the GINR to the IE and the IE will have ten Business Days to answer the request for additional information without impacting the study timeline. The IE will be notified that action is required via a RIOO system automated email.

[PGRR082: Delete Section 5.3.1 above upon system implementation.]

5.4.2 Full Interconnection Study

(1) An FIS consists of the set of steady-state, dynamic, short-circuit, facility studies, along with other relevant studies that are necessary to determine the reliability impact on affected Transmission Facilities and identify the Transmission Facilities that are needed to reliably interconnect the new or modified Generation Resource to the ERCOT System,

in accordance with the Planning Guide. The FIS is not intended to determine the deliverability of power from the proposed Generation Resource to market or to ensure that the proposed Generation Resource does not experience any congestion-related curtailment.

(2) The IE must provide the appropriate Full Interconnection Study Application Fee and proof of site control. IEs are not required to resubmit proof of site control for GINRs meeting paragraph (1)(b) of Section 5.1.1, Applicability.

(3) The IE can request an FIS at any time after ERCOT deems the initial GINR application complete, which can be before completion of the Security Screening Study, but must respect the timeline set forth in paragraph (5) of Section 5.4.1, Security Screening Study. Requesting both studies at the same time may shorten the overall time to complete the GINR process due to overlap of work on both studies.

(4) ERCOT shall manage a confidential email list (Transmission Owner Generation Interconnection) to facilitate communication of confidential GINR-related information among TSP(s) and ERCOT. Membership to this email list will be limited to ERCOT and appropriate TSP personnel.

[PGRR082: Replace Section 5.4.2 above with the following upon system implementation:]

5.3.2 Full Interconnection Study

(1) An FIS consists of the set of steady-state, stability, short-circuit, facility, and/or other relevant studies that are necessary to determine the reliability impact of a large generator on affected Transmission Facilities and identify the Transmission Facilities that are needed to reliably interconnect the new or modified generator to the ERCOT System. The FIS is not intended to determine the deliverability of power from the proposed Generation Resource to market or to ensure that the proposed Generation Resource does not experience any congestion-related curtailment.

(2) For an interconnection request involving a large generator interconnecting at distribution voltage, the FIS shall evaluate only the transmission-level impacts, if any, of the proposed generator, and the affected DSP shall provide the lead TSP all information concerning the DSP's facilities or the proposed generator interconnection as may be requested by the TSP for the purpose of completing any one or more FIS studies.

(3) To initiate an FIS, the IE must submit each of the following via the online RIOO system:

(a) A request to proceed with the FIS via the online RIOO system;

(b) Complete Resource Registration data in the format prescribed by ERCOT with applicable information required for interconnection studies identified in the Resource Registration Glossary for the applicable Resource type. This information, includes, among other things, the appropriate dynamic model for the proposed generator and results of the model quality tests and associated simulation files as

described in paragraph (5)(c) of Section 6.2, Dynamics Model Development, subject to performance and usability verification by the lead TSP with approval from ERCOT through the FIS process. Dynamic model data shall be provided using the appropriate dynamic model template. Paragraph (5) of Section 6.2 and the Dynamics Working Group Procedure Manual contain more detail and IE dynamics data requirements. Data submitted for transient stability models shall be compatible with the current version of the planning and operations model software as described in the Dynamics Working Group Procedure Manual. If no compatible model exists, the IE shall work with a consultant or software vendor to develop and supply accurate/appropriate models along with other associated data. These models shall be incorporated into the standard model libraries of all software packages;

(c) A Full Interconnection Study Application Fee as described in the ERCOT Fee Schedule in the ERCOT Nodal Protocols, with the MW amount determined based on:

(i) The MW of additional installed capacity for GIMs not meeting paragraph (1)(c)(ii) of Section 5.2.1, Applicability; or

(ii) Total MW capacity for GIMs meeting paragraph (1)(c)(ii) of Section 5.2.1;

(d) Proof of site control as described in Section 5.3.2.1, Proof of Site Control; and

(e) A declaration in Section 8, Attachment C, Declaration of Department of Defense Notification, certifying that:

(i) The IE has notified the Department of Defense (DOD) Siting Clearinghouse of the proposed Generation Resource and requested an informal or formal review as described in 32 C.F.R. § 211.1; or

(ii) The IE's proposed Generation Resource is not required to provide notice to the DOD and Federal Aviation Administration (FAA) because the project does not meet the criteria requiring notice to the FAA under 14 C.F.R. § 77.9.

(4) The IE can request an FIS for an active project before completion of the Security Screening Study or at any other time after ERCOT deems the initial GIM application complete, but must comply with the timeline set forth in paragraph (5) of Section 5.3.1, Security Screening Study. Requesting both studies at the same time may shorten the overall time to complete the GIM process due to overlap of work on both studies.

(5) Payment of the ERCOT FIS Application Fee does not affect the IE's independent responsibility to pay for FIS studies conducted by the TSP or for any DSP studies.

(6) ERCOT shall manage a confidential email list (Transmission Owner Generation Interconnection) to facilitate communication of confidential GIM-related information among TSP(s) and ERCOT. Membership to this email list will be limited to ERCOT and

appropriate TSP personnel.

(7) If any of the items required for the FIS request pursuant to paragraph (3) above are deemed not acceptable by ERCOT or are not submitted, then the IE must submit any omitted items and resolve and resubmit any deficient items. If the FIS request is not deemed complete by ERCOT within 60 days of submission of the FIS request, the FIS will be considered to have not been requested for the purpose of meeting paragraph (5) of Section 5.3.1, Security Screening Study. If the 180-day limit specified in paragraph (5) of Section 5.3.1 has expired, the GIM will be cancelled immediately. If the 180-day limit has not expired and the deficiency is not resolved before the 180-day limit, the GIM will be cancelled upon expiration of the 180-day limit.

Revised ERCOT Impact Analysis Report

PGRR Number	091	PGRR Title	FIS Application Completion 60-Day Limit
Impact Analysis Date		July 27, 2021	
Estimated Cost/Budgetary Impact		Between $15k and $30k Additional Cost to Implement in Passport: None	
Estimated Time Requirements		Interim Solution: Manual Process No project required. This Planning Guide Revision Request (PGRR) can be implemented using manual business processes and can take effect upon Public Utility Commission of Texas (PUCT) approval. Long-term solution: Automation The timeline for automating this PGRR is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Please see the Project Priority List (PPL) for additional information. Estimated project duration: 3 to 5 months in current systems Passport Schedule Risk Assessment: No Risk to Schedule See Comments	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Resource Integration and Ongoing Operations (RIOO) 100%	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this PGRR.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments

Revised ERCOT Impact Analysis Report

If approved, ERCOT plans to automate system changes as part of a project after the completion of the in-flight RIOO project.

TAC Report

RMGRR Number	165	RMGRR Title	Modify ERCOT Pre-Launch Responsibilities in a Mass Transition
Date of Decision		July 28, 2021	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		Upon Public Utility Commission of Texas (PUCT) approval – August 20, 2021	
Priority and Rank Assigned		Not applicable	
Retail Market Guide Sections Requiring Revision		2.2, Acronyms 7.11.1.1.1, Mass Transition Initiation 7.11.1.4.1.2, ERCOT Pre-Launch Responsibilities in a Mass Transition	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Retail Market Guide Revision Request (RMGRR) allows ERCOT discretion in scheduling and conducting a Mass Transition project coordination call.	
Reason for Revision		☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*	
Business Case		This RMGRR is the result of lessons learned from the recent Winter Storm Uri and the associated Provider of Last Resort (POLR) drops. It allows ERCOT the discretion on which Market Participants to invite to the Mass Transition market coordination calls when Electric	

TAC Report

	Service Identifiers (ESI IDs) involved in the Mass Transition are allocated only to Volunteer Retail Electric Providers (VREPs) or are only in certain Transmission and/or Distribution Service Provider (TDSP) footprints. It is unnecessary for ERCOT to involve all Market Participants when a Mass Transition does not require their involvement.
RMS Decision	On 6/9/21, RMS voted unanimously via roll call to recommend approval of RMGRR165 as amended by the 6/4/21 PUCT Staff comments. All Market Segments participated in the vote. On 7/13/21, RMS voted unanimously via roll call to endorse and forward to TAC the 6/9/21 RMS Report and the Impact Analysis for RMGRR165. All Market Segments participated in the vote.
Summary of RMS Discussion	On 6/9/21, participants reviewed the 6/4/21 PUCT Staff and 6/7/21 OPUC comments. On 7/13/21, there was no discussion.
TAC Decision	On 7/28/21, TAC voted unanimously via roll call to recommend approval of RMGRR165 as recommended by RMS in the 7/13/21 RMS Report, with a recommended effective date of upon PUCT approval; and the Revised Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/28/21, there was no discussion.
ERCOT Opinion	ERCOT supports approval of RMGRR165.
ERCOT Market Impact Statement	ERCOT Staff has reviewed RMGRR165 and believes the market impact for RMGRR165 provides one or more of the following benefits: transparency, efficiency, and/or reliability; and/or aligns with current market rules.

Sponsor	
Name	Kyle Patrick on behalf of Texas SET
E-mail Address	Kyle.Patrick@nrg.com
Company	NRG
Phone Number	713-304-0698
Cell Number	682-564-4434

TAC Report

Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
PUCT Staff 060421	Requested that representatives of the Office of Public Utility Counsel (OPUC) be included in the parties notified in advance of a Mass Transition and added the acronym 'OPUC' to Section 2.2
OPUC 060721	Supported the 6/4/21 PUCT Staff comments

Market Rules Notes

None

Proposed Guide Language Revision

2.2 ACRONYMS

OPUC Office of Public Utility Counsel

7.11.1.1.1 Mass Transition Initiation

(1) If ERCOT has reason to expect that it may be necessary to initiate a Mass Transition on a given Business Day, it may notify PUCT and Office of Public Utility Counsel (OPUC) Staff and potentially affected TDSPs and POLRs that a Mass Transition might commence that day. Such notification shall not disclose the name or DUNS # of the potential Losing CR, the number of ESI IDs involved, or any other Protected Information.

(2) If ERCOT determines that no Mass Transition is necessary, and preliminary notice has been provided to potentially affected parties in accordance with paragraph (1) above, ERCOT shall then notify PUCT and OPUC Staff and the potentially affected TDSPs and POLRs that the Mass Transition will not occur on that Business Day.

(3) Upon confirmation that a Mass Transition will occur, ERCOT shall provide an initial Mass Transition Market Notice to affected TDSPs, POLRs, the Losing CR, and appropriate PUCT and OPUC Staff. If a Mass Transition is initiated on a Business Day

prior to a weekend or ERCOT holiday, the initial Mass Transition project coordination call will be scheduled for that Business Day. See Section 9, Appendices, Appendix F2, Timeline for Initiation of a Mass Transition. The initial Mass Transition Market Notice shall include:

(a) Confirmation of a Mass Transition event;

(b) The total number of ESI IDs of the Losing CR;

(c) The estimated Load of the Losing CR;

(d) The Mass Transition Date; and

(e) Logistical details for the initial Mass Transition project coordination call, which will be scheduled for the same or the next Business Day. If the Mass Transition is initiated on a Business Day prior to a weekend or ERCOT holiday the initial project coordination call must be scheduled for the same Business Day.

(4) The same day as and following the initial Mass Transition Market Notice to affected parties, ERCOT will provide a Mass Transition Market Notice to Transition/Acquisition contacts for Load Serving Entities (LSEs) and TDSPs, and the Retail Market Subcommittee (RMS) e-mail ListServ. This Market Notice shall include:

(a) Confirmation of a Mass Transition event;

(b) The name and DUNS # of the Losing CR;

(c) The total number of ESI IDs of the Losing CR;

(d) The estimated Load of the Losing CR; and

(e) The Mass Transition Date.

(5) Should issues arise that are not addressed in this document or the ERCOT Nodal Protocols, ERCOT and the affected parties will work to resolve such issues.

7.11.1.4.1.2 ERCOT Pre-Launch Responsibilities in a Mass Transition

(1) Identify the defaulting CR;

(2) Identify the appropriate POLR(s) or designated CR;

(3) Identify all of the affected TDSPs and CRs (current, CSA, and pending new CR);

(4) Determine the ESI IDs by designated POLR class associated to the Mass Transition and notify the affected parties according to the following:

(a) If all ESI IDs associated with the Mass Transition will only be allocated among Volunteer Retail Electric Providers (VREPs), then ERCOT will only need to include affected parties in the Mass Transition project; or

(b) If all ESI IDs associated with the Mass Transition will be allocated among Large Service Providers (LSPs) and VREPs, then ERCOT will include affected parties in the Mass Transition project.

(5) Determine the Mass Transition launch timeline;

(6) Determine the Mass Transition completion date to be no more than five days after ERCOT generates and the TDSP receives the 814_03, Enrollment Notification Request, with the Mass Transition indicator, for all affected ESI IDs;

(7) Designate the ERCOT Mass Transition project lead;

(8) Schedule and conduct Mass Transition project coordination calls with affected parties;

(9) Complete and disseminate required Mass Transition Market Notices;

(10) Delete or disable CSAs to prevent the Losing CR from becoming the Retail Electric Provider (REP) responsible for an ESI ID (REP of record) on an ongoing basis after the Mass Transition has begun;

(11) Identify Pending TX SETs associated with those affected ESI IDs;

(12) Send a list of ESI IDs targeted to the POLRs or designated CRs where they are expected to become REP of record and to the affected TDSP(s) (see Section 9, Appendices, Appendix F4, ERCOT Template - Electric Service Identifiers for Gaining Competitive Retailer/Transmission and/or Distribution Service Provider Use);

(13) Assign ESI IDs to the POLR(s) as directed by ALA and the POLR rule;

(14) Provide a list of ESI IDs to any CR (both POLR and non-POLR) of any Pending switch transactions with a scheduled date greater than two Business Days after the Mass Transition Date (including in-review and scheduled). See Section 9, Appendices, Appendix F5, ERCOT Template – Electric Service Identifiers for New Competitive Retailer with Pending Transactions; and

(15) Manage the POLR DUNS # list according to the registration by the POLR Entities.

Revised ERCOT Impact Analysis Report

RMGRR Number	165	RMGRR Title	Modify ERCOT Pre-Launch Responsibilities in a Mass Transition
Impact Analysis Date		July 27, 2021	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Retail Market Guide Revision Request (RMGRR) can take effect upon Public Utility Commission of Texas (PUCT) approval.	
ERCOT Staffing Impacts (across all areas)		Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this RMGRR.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

Evaluation of Interim Solutions or Alternatives for a More Efficient Implementation
None offered.

Comments
None.

RMGRR Comments

RMGRR Number	165	RMGRR Title	Modify ERCOT Pre-Launch Responsibilities in a Mass Transition

Date	June 4, 2021

Submitter's Information	
Name	Public Utility Commission of Texas (PUCT) Staff
E-mail Address	marketanalysis@puc.texas.gov
Company	PUCT
Phone Number	512-936-7371
Cell Number	
Market Segment	Not Applicable

Comments

PUCT Staff submits these comments to request that representatives of the Office of Public Utility Counsel (OPUC) be included in the parties notified in advance of a Mass Transition.

OPUC represents residential and small commercial consumers, as a class, at both ERCOT and the PUCT. Including OPUC in the preliminary and initial Mass Transition notice will allow it to better assist consumers affected by the event.

These comments also add the abbreviation 'OPUC' to Section 2.2, Acronyms.

Revised Cover Page Language

Retail Market Guide Sections Requiring Revision	2.2, Acronyms 7.11.1.1.1, Mass Transition Initiation 7.11.1.4.1.2, ERCOT Pre-Launch Responsibilities in a Mass Transition

Revised Proposed Guide Language

RMGRR Comments

2.2 ACRONYMS

OPUC Office of Public Utility Counsel

7.11.1.1.1 Mass Transition Initiation

(1) If ERCOT has reason to expect that it may be necessary to initiate a Mass Transition on a given Business Day, it may notify PUCT and Office of Public Utility Counsel (OPUC) Staff and potentially affected TDSPs and POLRs that a Mass Transition might commence that day. Such notification shall not disclose the name or DUNS # of the potential Losing CR, the number of ESI IDs involved, or any other Protected Information.

(2) If ERCOT determines that no Mass Transition is necessary, and preliminary notice has been provided to potentially affected parties in accordance with paragraph (1) above, ERCOT shall then notify PUCT and OPUC Staff and the potentially affected TDSPs and POLRs that the Mass Transition will not occur on that Business Day.

(3) Upon confirmation that a Mass Transition will occur, ERCOT shall provide an initial Mass Transition Market Notice to affected TDSPs, POLRs, the Losing CR, and appropriate PUCT and OPUC Staff. If a Mass Transition is initiated on a Business Day prior to a weekend or ERCOT holiday, the initial Mass Transition project coordination call will be scheduled for that Business Day. See Section 9, Appendices, Appendix F2, Timeline for Initiation of a Mass Transition. The initial Mass Transition Market Notice shall include:

(a) Confirmation of a Mass Transition event;

(b) The total number of ESI IDs of the Losing CR;

(c) The estimated Load of the Losing CR;

(d) The Mass Transition Date; and

(e) Logistical details for the initial Mass Transition project coordination call, which will be scheduled for the same or the next Business Day. If the Mass Transition is initiated on a Business Day prior to a weekend or ERCOT holiday the initial project coordination call must be scheduled for the same Business Day.

(4) The same day as and following the initial Mass Transition Market Notice to affected parties, ERCOT will provide a Mass Transition Market Notice to Transition/Acquisition contacts for Load Serving Entities (LSEs) and TDSPs, and the Retail Market Subcommittee (RMS) e-mail ListServ. This Market Notice shall include:

(a) Confirmation of a Mass Transition event;

(b) The name and DUNS # of the Losing CR;

(c) The total number of ESI IDs of the Losing CR;

(d) The estimated Load of the Losing CR; and

(e) The Mass Transition Date.

(5) Should issues arise that are not addressed in this document or the ERCOT Nodal Protocols, ERCOT and the affected parties will work to resolve such issues.

7.11.1.4.1.2 ERCOT Pre-Launch Responsibilities in a Mass Transition

(1) Identify the defaulting CR;

(2) Identify the appropriate POLR(s) or designated CR;

(3) Identify all of the affected TDSPs and CRs (current, CSA, and pending new CR);

(4) Determine the ESI IDs by designated POLR class associated to the Mass Transition and notify the affected parties according to the following:

(a) If all ESI IDs associated with the Mass Transition will only be allocated among Volunteer Retail Electric Providers (VREPs), then ERCOT will only need to include affected parties in the Mass Transition project; or

(b) If all ESI IDs associated with the Mass Transition will be allocated among Large Service Providers (LSPs) and VREPs, then ERCOT will include affected parties in the Mass Transition project.

(5) Determine the Mass Transition launch timeline;

(6) Determine the Mass Transition completion date to be no more than five days after ERCOT generates and the TDSP receives the 814_03, Enrollment Notification Request, with the Mass Transition indicator, for all affected ESI IDs;

(7) Designate the ERCOT Mass Transition project lead;

(8) Schedule and conduct Mass Transition project coordination calls with affected parties;

(9) Complete and disseminate required Mass Transition Market Notices;

(10) Delete or disable CSAs to prevent the Losing CR from becoming the Retail Electric Provider (REP) responsible for an ESI ID (REP of record) on an ongoing basis after the Mass Transition has begun;

(11) Identify Pending TX SETs associated with those affected ESI IDs;

(12) Send a list of ESI IDs targeted to the POLRs or designated CRs where they are expected to become REP of record and to the affected TDSP(s) (see Section 9, Appendices,

Appendix F4, ERCOT Template - Electric Service Identifiers for Gaining Competitive Retailer/Transmission and/or Distribution Service Provider Use);

(13) Assign ESI IDs to the POLR(s) as directed by ALA and the POLR rule;

(14) Provide a list of ESI IDs to any CR (both POLR and non-POLR) of any Pending switch transactions with a scheduled date greater than two Business Days after the Mass Transition Date (including in-review and scheduled). See Section 9, Appendices, Appendix F5, ERCOT Template – Electric Service Identifiers for New Competitive Retailer with Pending Transactions; and

(15) Manage the POLR DUNS # list according to the registration by the POLR Entities.