**ERCOT Nodal Operating Guides**

**Section 2: System Operations and Control Requirements**

**May 1, 2024**

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# System Operations and Control Requirements

2.1 Operational Duties

(1) The duties of ERCOT are described in relevant sections of the Protocols and North American Electric Reliability Corporation (NERC) Reliability Standards. These Operating Guides assume that all actions taken will be on components of, or related to, the ERCOT System unless otherwise specified. The primary operational duties of ERCOT are to ensure the reliability of the ERCOT System. In doing this ERCOT shall:

(2) Perform operational planning:

(a) Perform the Reliability Unit Commitment (RUC) processes in order to commit additional resources as needed to maintain reliability;

(b) Perform operational ERCOT Transmission Grid reliability studies, including those related to generation and load interconnection responsibilities;

(c) Review all Outages of Generation Resources and major transmission lines or components to identify and correct possible failure to meet credible N-1 criteria. This shall include possible failure to meet N-1 criteria not resolved through the Day-Ahead process;

(d) Perform load flows and security analyses of Outages submitted by Qualified Scheduling Entities (QSEs) or Transmission Service Providers (TSPs) as a basis for approval or rejection as described in Protocol Section 3.1, Outage Coordination;

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| [NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:](d) Perform load flows and security analyses of Outages submitted by Qualified Scheduling Entities (QSEs), Transmission Service Providers (TSPs), or Direct Current Tie Operators (DCTOs) as a basis for approval or rejection as described in Protocol Section 3.1, Outage Coordination;  |

(e) Withdraw approval of a scheduled Outage if unable to meet credible N-1 criteria after all other reasonable options are exercised as described in Protocol Section 3.1;

(f) Serve as the point of contact for initiation of generation interconnection to the ERCOT Transmission Grid;

(g) Forecast Load and Resources for the next seven days for reliability planning; and

(h) Ensure that sufficient Resources in the proper location and required Ancillary Services have been committed for all expected Load on a Day-Ahead and Real-Time basis.

(3) Operate energy and Ancillary Service markets:

(a) Administer a Congestion Revenue Rights (CRR) market;

(b) Administer a Day-Ahead Market (DAM) including both energy and Ancillary Service;

(c) Administer the RUC processes;

(d) If necessary, administer a Supplemental Ancillary Service Market (SASM); and

(e) Administer a Real-Time energy market using Security-Constrained Economic Dispatch (SCED).

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| [NOGRR211: Replace paragraph (3) above with the following upon system implementation of NPRR1007:](3) Operate energy and Ancillary Service markets:(a) Administer a Congestion Revenue Rights (CRR) market;(b) Administer a Day-Ahead Market (DAM) including both energy and Ancillary Service;(c) Administer the RUC processes; and(d) Administer a Real-Time Market (RTM) including energy and Ancillary Services using Security-Constrained Economic Dispatch (SCED). |

(4) Supervise the ERCOT System to meet NERC Reliability Standards:

(a) Monitor and evaluate ERCOT System conditions on a continuous basis;

(b) Coordinate with Transmission Operators (TOs), ERCOT System events to maintain or restore reliability;

(c) Dispatch generation via the SCED process and deployment of Ancillary Services to control frequency and congestion;

(d) Provide access to the ERCOT System on a nondiscriminatory basis;

(e) Approve schedules of interchange transactions across the Direct Current Ties (DC Ties); and

(f) Direct emergency operations.

(5) Collect and Disseminate Information:

(a) Collect, process, and disseminate market, operational and settlement information;

(b) Provide relevant operational information to Market Participants over the Market Information System (MIS);

(c) Collect and maintain operational data required by the Public Utility Commission of Texas (PUCT), NERC and Protocols;

(d) Receive reports from TOs and QSEs and forward them to the Department of Energy (DOE), NERC, and/or other Governmental Authority as required;

(e) Submit reports to DOE, NERC, and/or other Governmental Authority as required; and

(f) Record and report accumulated time error.

2.2 System Monitoring and Control

2.2.1 Overview

(1) ERCOT will maintain continuous surveillance of the status of operating conditions within ERCOT and act as a central information collection and dissemination point for Market Participants.

(2) ERCOT is designated to receive information required to continually monitor the operating conditions of the ERCOT System and to order individual Qualified Scheduling Entities (QSEs) and/or Transmission Operators (TOs) to make changes to ensure ongoing security and reliability of ERCOT.

(3) ERCOT shall maintain, monitor, and/or direct the following in accordance with the Protocols. This includes but is not limited to:

(a) Resources - Monitor, deploy, commit and gather data for settlement of Resources in order to maintain reliability and accurately settle energy capacity and Ancillary Service markets as described in the following Protocol Sections:

(i) Protocol Section 3, Management Activities for the ERCOT System;

(ii) Protocol Section 4, Day-Ahead Operations;

(iii) Protocol Section 5, Transmission Security Analysis and Reliability Unit Commitment; and

(iv) Protocol Section 6, Adjustment Period and Real-Time Operations.

(b) ERCOT Transmission Grid:

(i) Monitor line loading and power transfers;

(ii) Coordinate Planned Outages;

(iii) Monitor and detect Forced Outages;

(iv) Perform contingency analyses and direct re-dispatch to maintain reliable operations;

(v) Monitor and coordinate maintenance and construction schedules;

(vi) Monitor and control voltage levels; and

(vii) Monitor Reactive Power flows.

(c) System Operation:

(i) Monitor power flows with non-ERCOT systems;

(ii) Maintain and monitor Ancillary Services plans and delivery;

(iii) Maintain and document compliance with transmission security criteria;

(iv) Monitor performance of providers of Ancillary Services;

(v) Manage inadvertent energy account balances with non-ERCOT systems;

(vi) Direct Time Error correction;

(vii) Issue and direct Operating Condition Notices (OCNs), Advisories, Watches, and Emergency Notices; and

(viii) Direct emergency and short supply operations.

(d) Information Management:

(i) Monitor and coordinate information for daily planning, hourly reporting and minute-by-minute operation;

(ii) Validate the accuracy of the Real-Time data; and

(iii) Operate the Market Information System (MIS), Energy Management System (EMS) and Market Management System (MMS) to disseminate Real-Time, hourly accounting, and operations plan data between ERCOT and each QSE and TO.

2.2.2 Security Criteria

(1) Technical limits established for the operation of transmission equipment shall be applied consistently in planning and engineering studies, Congestion Revenue Rights (CRRs), Day-Ahead studies, Real-Time security analyses, and operator actions.

(2) ERCOT shall operate the system such that pre-contingency flows are within applicable Transmission Facility Ratings.

(3) ERCOT shall operate the system such that, unless an Emergency Condition has been declared by ERCOT, the occurrence of a Credible Single Contingency will not cause any of the following conditions:

(a) Uncontrolled breakup of the ERCOT Transmission Grid;

(b) Loading of Transmission Facilities above defined Emergency Ratings that cannot be eliminated in time to prevent damage or failure following the loss through execution of a Constraint Management Plan (CMP);

(c) Transmission voltage levels outside system design limits that cannot be corrected through execution of a CMP before voltage instability or collapse occurs; or

(d) Customer Outages, except for Load that is included in a CMP, high set interruptible and radially served Loads.

2.2.3 Response to Transient Voltage Disturbance

(1) Generation Resources should be designed in accordance with Section 6.2, System Protective Relaying, in order to properly respond to transient voltage disturbances.

2.2.4 Load Frequency Control

(1) ERCOT shall operate the Load Frequency Control (LFC) system to maintain the scheduled frequency at 60 Hz (correcting periodically for time error) and to minimize the use of energy from Resources providing Regulation Service.

(2) The ERCOT LFC system shall deploy Regulation Service energy, and release Responsive Reserve (RRS) and ERCOT Contingency Reserve Service (ECRS) capacity to Security-Constrained Economic Dispatch (SCED), as necessary, in accordance with Protocol Section 6.5.7.6, Load Frequency Control, to meet North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT shall purchase Regulation Service to provide satisfactory frequency control performance for the ERCOT Region. ERCOT shall determine the satisfactory amount of Regulation Service, required by statistical analysis of possible Resource Outages and Load forecast error, to expect operation of 95% of hours without deploying RRS.

(3) QSEs shall use Automatic Generation Control (AGC) to direct the output of generation facilities providing Regulation.

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| [NOGRR211: Replace Section 2.2.4 above with the following upon system implementation of NPRR1007:]***2.2.4 Load Frequency Control***(1) ERCOT shall operate the Load Frequency Control (LFC) system to maintain the scheduled frequency at 60 Hz (correcting periodically for time error) and to minimize the use of energy from Resources providing Regulation Service.(2) The ERCOT LFC system shall deploy Regulation Service, Responsive Reserve (RRS), and ERCOT Contingency Reserve Service (ECRS) as necessary in accordance with Protocol Section 6.5.7.6.2, LFC Deployment, to meet North American Electric Reliability Corporation (NERC) Reliability Standards. ERCOT shall purchase Regulation Service to provide satisfactory frequency control performance for the ERCOT Region. ERCOT shall determine the satisfactory amount of Regulation Service, required by statistical analysis of possible Resource Outages and Load forecast error, to expect operation of 95% of hours without deploying RRS.(3) QSEs shall use Automatic Generation Control (AGC) to direct the output of generation facilities providing Regulation.  |

2.2.4.1 Maintenance and Verification

(1) Each provider of Regulation Services will properly maintain AGC equipment. Performance of AGC will be verified by the results of performance metrics for Ancillary Service providers described in the Protocols. ERCOT will initiate a regulation survey to evaluate the performance of all AGC equipment in the ERCOT Region.

2.2.4.2 Regulation Provider Loss of AGC

(1) If a QSE providing Regulation Services loses its AGC for any reason, it will notify ERCOT as soon as practicable of the reason for and estimated duration of the loss. ERCOT will assess whether additional action should be taken to maintain system frequency. Possible ERCOT actions include opening a Supplemental Ancillary Services Market (SASM) per Protocol Section 6.4.9.2, Supplemental Ancillary Services Market, for the period of anticipated loss.

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| [NOGRR211: Replace paragraph (1) above with the following upon system implementation of NPRR1007:](1) If a QSE providing Regulation Services loses its AGC for any reason, it will notify ERCOT as soon as practicable of the reason for and estimated duration of the loss. ERCOT will assess whether additional action should be taken to maintain system frequency.  |

2.2.4.3 ERCOT Loss of AGC

(1) ERCOT has back-up facilities in place for loss of control systems. In the event that these backup facilities also fail to perform, ERCOT shall direct a QSE providing regulation to implement Constant Frequency Control (CFC) for the duration of the control loss. ERCOT will direct the QSE providing CFC to enter the appropriate bias into their control system. If a QSE on CFC develops a problem with regulating room, ERCOT will order additional regulation energy from another QSE to create regulation room.

(2) ERCOT shall conduct unannounced testing to verify a QSE’s capability to operate in CFC mode. Only QSEs with at least 350 MW of spinning reserve room will be tested. QSEs shall be tested at least once every three years. At a time determined solely by ERCOT, ERCOT will direct the QSE to operate under CFC mode. Once instructed by ERCOT, the QSE will have five minutes to switch to CFC mode. The duration of this test shall be no more than 15 minutes. ERCOT shall maintain the list of QSEs that have successfully demonstrated their capability to operate in CFC mode.

### *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, via telemetry and verbal notification, 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. For each Generation Resource that is On-Line but not producing real power and is not capable of providing Reactive Power, each QSE must still telemeter its AVR status to ERCOT, but is not required to provide verbal notifications of its AVR status changes to ERCOT during these operating conditions.

(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).

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| [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.

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| [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. |

2.2.6 Power System Stabilizers

(1) Generation Resources with Power System Stabilizers (PSSs) shall keep their PSSs in-service (“On” or energized and performing as designed by the manufacturer) unless the PSS is installed but not in service as described in paragraph (4)(a)(ii) below. When available, the PSS shall be active and responsive at all times the generator is synchronized to the ERCOT Transmission Grid and operating at or above its Low Sustained Limit (LSL). However, if the PSS of a Generation Resource is set to be active and responsive at a point above the LSL for technical reasons, the Generation Resource may request ERCOT to allow an exception to the requirement that the PSS be active anytime the Generation Resource is at or above its LSL. In order to obtain the exception, the Generation Resource shall notify ERCOT and provide the necessary technical information to ERCOT to justify a higher activation point for the PSS.

(2) Resource Entities shall notify their QSEs of any change in PSS status (e.g. PSS unavailability due to maintenance or failure and when the PSS returns to normal operation). QSEs shall notify ERCOT and the TO at the Point of Interconnection (POI) of any change in PSS status and shall supply PSS status logs to ERCOT upon request per Protocol Section 6.5.5.1, Changes in Resource Status.

(3) Synchronous Generation Resources greater than 10 MW installed after January 1, 2008 and on or before December 1, 2010 shall install a PSS and place the PSS in service by June 1, 2011. Synchronous Generation Resources greater than 10 MW installed after December 1, 2010 shall install a PSS and place the PSS in-service prior to the Resource Commissioning Date of the Generation Resource. The Generation Resource shall establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(4) Synchronous Generation Resources greater than 10 MW installed before January 1, 2008 are subject to the following requirements:

(a) All Generation Resources that are in this category shall notify ERCOT and the TSP:

(i) Whether or not a PSS has been installed; and

(ii) Whether or not PSS settings have been determined and the PSS has been or will be placed in-service.

(b) If a PSS was in-service prior to January 1, 2008, the PSS shall remain in-service with the established PSS settings, provided that ERCOT may direct the Generation Resource to modify the settings. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics.

(c) If a PSS is newly installed and/or placed in-service the Generation Resource shall establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz. The PSS settings shall be tested and tuned to ensure the PSS has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(5) If an excitation system on a synchronous Generation Resource greater than 10 MW is modified or replaced after January 1, 2008, the Generation Resource shall install a PSS, establish PSS settings to dampen modes with oscillations within the range of 0.2 Hz to 2 Hz, and place the PSS in-service. The settings shall be tested and tuned to ensure the excitation system has appropriate damping characteristics. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(6) If it is determined that a change in PSS settings or the addition of a PSS to a synchronous Generation Resource would improve overall system performance, ERCOT shall coordinate with the Generation Resource owner to determine appropriate settings. Within 180 days of determining appropriate settings, the Generation Resource owner shall revise the PSS setting and/or install the PSS. Any PSS setting established pursuant to this section shall be established to dampen modes with oscillations as directed by ERCOT and place the PSS in-service. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

(7) At least every ten calendar years, Resource Entities shall conduct a PSS test or verify PSS performance based on operational data for the purpose of model verification on PSSs. All new Generation Resources shall conduct a PSS test within five years of the initial PSS test that was approved as part of the commissioning process. All subsequent tests shall be conducted on a ten year cycle. Additionally, if PSS equipment characteristics are modified, the Resource Entity shall conduct a performance test 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 and include the operational data used to verify the modeling parameters. Any models created from the test data must be a standard PSS/E dynamic model or ERCOT and TSP approved user written model. Final PSS settings shall be provided to ERCOT and the TSP within 30 days of the PSS in-service date.

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

(8) An exemption may be granted for the testing requirements listed above if the Resource on which the PSS is installed has a current ANCF, as calculated per paragraph (4) of Section 2.2.5, Automatic Voltage Regulators, of 5% or less over the most recent three calendar years preceding the planned testing calendar year. 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 the ANCF exemption, 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.

(9) The results of PSS tests or PSS performance verification shall be supplied to ERCOT and the TSP within 30 days of a request from ERCOT.

2.2.7 Turbine Speed Governors

(1) A Governor shall be in-service whenever the Generation Resource or Energy Storage Resource (ESR) is connected to the ERCOT System, or Settlement Only Generator (SOG) is connected to the ERCOT Transmission Grid.

(2) Generation Resources and ESRs that have not been evaluated in at least eight Frequency Measurable Events (FMEs) within 36 months shall conduct Governor performance tests within 12 months using one of the test methods or historical methods specified in Section 8, Attachment C, Turbine Governor Speed Tests. The Resource Entity shall then provide test results to ERCOT.

(3) Generation Resources and ESRs, except steam turbines of Combined Cycle Generation Resources, Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Self-Generators (SOTSGs) shall have Governor droop characteristics and Governor Dead-Band settings no greater than those shown below in Table 1, Maximum Governor Dead-Band Settings, and Table 2, Maximum Governor Droop Settings, as defined below:

Table 1: Maximum Governor Dead-Band Settings

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| **Resource Type** | **Max. Deadband** |
| Steam Turbines withMechanical Governors | +/- 0.034 Hz |
| Hydro Turbines with Mechanical Governors | +/- 0.034 Hz |
| All Other GeneratingUnits/Generating Facilities/ESRs | +/- 0.017 Hz |
| Controllable Load Resources  | +/- 0.036 Hz |

Table 2: Maximum Governor Droop Settings

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| **Generator Type** | **Max. Droop % Setting** |
| Combustion Turbine (Combined Cycle) | 4% |
| All Other GeneratingUnits/Generating Facilities/ESRs/Controllable Load Resources | 5% |

(4) If ERCOT determines that ERCOT System reliability would be enhanced, for a defined period of time, ERCOT may direct Wind-powered Generation Resources (WGRs) under the control of a Remedial Action Scheme (RAS) to limit power increases due to frequency if there is risk of a RAS operation due to a low frequency FME.

2.2.8 Performance/Disturbance/Compliance Analysis

(1) Performance/Disturbance/Compliance analysis shall be performed by ERCOT for the purpose of ensuring conformance with the Protocols and Operating Guides. All Generation Resources, ESRs, SOTGs, SOTSGs, and Controllable Load Resources, except nuclear-powered Resources or WGRs with a permanent exemption approved by ERCOT, must respond to frequency disturbances with a Governor droop as specified in Section 2.2.7, Turbine Speed Governors. Each Generation Resource, ESR, SOTG, SOTSG, and Controllable Load Resource based on participation in at least eight FMEs, shall meet a minimum 12-month rolling average initial Primary Frequency Response performance and sustained Primary Frequency Response performance of 0.75 as calculated in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response. When assessing conformance with the Protocols and Operating Guides, ERCOT shall evaluate the annual rolling average and may exclude from the performance analysis Generation Resources, ESRs, SOTGs, SOTSGs, or Controllable Load Resources in accordance with, but not limited to, the following conditions:

(a) Operating within the larger of five MW or 2% of the High Sustained Limit (HSL) or the maximum capacity for low frequency disturbances;

(b) Operating within the larger of five MW or 2% of the HSL or the maximum capacity above the LSL for high frequency disturbances;

(c) For an ESR, while discharging, if operating within the larger of 3 MW or 2% of the Maximum Operating Discharge Power Limit for low frequency disturbances;

(d) For an ESR, while charging, if operating within the larger of 3 MW or 2% of the Maximum Operating Charge Power Limit for high frequency disturbances;

(e) For any Generation Resource carrying power augmentation, the maximum capacity will be computed as the HSL minus Non-Frequency Responsive Capacity (NFRC); or

(f) Having a technical or physical limitation filed with the ERCOT client representative and approved by ERCOT.

(2) Market Participants shall request an exemption from, or correction of, performance during an FME within 30 days of the MIS posting date of the “Initial and Sustained Frequency Response Unit Performance” report.

(3) ERCOT will, on an as needed basis, utilize the Performance, Disturbance, Compliance Working Group (PDCWG) as a technical resource in providing input for types of technical or physical limitations that may be approved by ERCOT.

(4) ERCOT shall make a regular report on selected system disturbances, documenting the response of individual Generation Resources, ESRs, and Controllable Load Resources. In addition, Resource Entities, QSEs, and individual members of the PDCWG are encouraged to work within their respective companies to enhance the performance of individual Generation Resource’s, ESR’s, or Controllable Load Resource’s control systems through application of the results of the PDCWG studies.

2.2.9 Time Error and Time Synchronization

2.2.9.1 Time Error

(1) Sustained frequency deviations from scheduled frequency result in Time Error. Time Error will be monitored and controlled in ERCOT as follows:

(a) Time Error Monitoring - ERCOT will monitor accumulated Time Error and initiate time corrections. The instantaneous Time Error is available to all QSEs on the ERCOT website.

(b) Time Error Correction - ERCOT may conduct Time Error correction at any time. However, ERCOT must promptly initiate Time Error correction if the Time Error exceeds +/- 30 seconds, unless operational circumstances require otherwise. ERCOT will initiate and terminate Time Error correction via Hotline call to QSEs representing Resources. The call initiating Time Error correction will include the frequency offset (- 0.02 Hz for fast and + 0.02 Hz for slow) and the start time. The Time Error correction may end when:

(i) The Time Error is within +/- 0.5 seconds of the target reference;

(ii) System events mandate termination;

(iii) The period of correction reaches five hours; or

(iv) After any hour without at least a 0.5 second error reduction.

2.2.9.2 Time Synchronization

(1) To promote accurate data reporting during an Energy Emergency Alert (EEA) and other system events, and to ensure transaction schedules are simultaneous, all QSEs and TOs, and ERCOT will maintain their control system time within ±3 seconds of the National Bureau of Standards (NBS) time signal. The NBS time signal shall set the time standard for ERCOT. ERCOT, QSEs and TOs are required to employ clocks, voice and data recording systems that synchronize automatically with the NBS on at least a weekly basis**.**

***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 and Energy Storage 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 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)andRegulation 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 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 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-DownandReg-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, 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; andc. 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 capacity, or reserved capacity from On-Line Generation Resources, capable of being ramped to a specified output level within ten minutes, operating at a specified output for at least two consecutive hours, and are dispatchable by Security-Constrained Economic Dispatch (SCED).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 two consecutive hours.c. Load Resources that are not Controllable Load Resources and may or may not be controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing ECRS must be capable of reducing Load in response to an Extensible Markup Language (XML) Dispatch Instruction within ten minutes and remain deployed until recalled by ERCOT. | 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 four consecutive hours. 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 four consecutive hours. c. Load Resources that are not Controllable Load Resources and that are not controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing Non-Spin must be capable of reducing Load in response to an XML Dispatch Instruction within 30 minutes and remain deployed until recalled by ERCOT. | 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. |

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| [NOGRR211: Replace paragraph (1) above with the following upon system implementation of NPRR1007:](1) The types of Ancillary Services required by ERCOT are described below:

| **ANCILLARY SERVICE TYPE** | **DESCRIPTION** | **ERCOT AUTHORITY ACTION** |
| --- | --- | --- |
| Regulation Down Service (Reg-Down)andRegulation 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-DownandReg-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; andc. 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 two consecutive hours.b. Controllable Load Resources dispatchable by Security-Constrained Economic Dispatch (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 two consecutive hours.c. Load Resources that are not Controllable Load Resources and may or may not be controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing ECRS must be capable of reducing Load in response to an Extensible Markup Language (XML) Dispatch Instruction within ten minutes and remain deployed until recalled by ERCOT. | 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 four consecutive hours. 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 four consecutive hours.c. Load Resources that are not Controllable Load Resources and that are not controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing Non-Spin must be capable of reducing Load in response to an XML Dispatch Instruction within 30 minutes and remain deployed until recalled by ERCOT. | 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. |

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2.3.1 Responsive Reserve

2.3.1.1 Obligation

(1) ERCOT operating reserve requirements are more restrictive than North American Electric Reliability Corporation (NERC) Reliability Standards. The RRS obligation is a minimum of 2300 MW. The amount of RRS procured may be adjusted as described in ERCOT Methodologies for Determining Ancillary Service Requirements or if ERCOT determines a reliability need for additional Ancillary Service Resources.

**2.3.1.2 Additional Operational Details for Responsive Reserve Providers**

(1) ERCOT shall specify the minimum amount of RRS provided by Generation Resources as outlined in Section 2.3.1.2.1, Limit on Generation Resources and Controllable Load Resources Providing RRS. QSE’s Generation Resources providing RRS must be On-Line, immediately responsive to system frequency deviations.

(2) RRS provided by a QSE shall meet the requirements as defined in paragraph (3) of Protocol Section 3.18, Resource Limits in Providing Ancillary Service.

(3) ERCOT shall issue a Verbal Dispatch Instruction (VDI) to QSEs of Generation Resources operating in synchronous condenser fast-response mode who provide MWs to the ERCOT System in response to a frequency event occurring at or below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18 when the energy is provided without an RRS deployment. The VDI shall be in the quantity of MWs (energy) supplied by the Generation Resource responding in synchronous condenser fast-response mode and shall relieve the QSE of its obligation for the equivalent RRS obligation quantity. If ERCOT issues an RRS deployment to the QSE responding with Generation Resources operating in synchronous condenser fast-response mode, ERCOT shall count the responding Generation Resource(s) MWs (energy) as part of its response to the RRS deployment.

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| [NOGRR211: Replace paragraph (3) above with the following upon system implementation of NPRR1007:](3) ERCOT shall issue Dispatch Instructions for RRS through Inter-Control Center Communications Protocol (ICCP) to a QSE representing a Generation Resource in synchronous condenser fast-response mode that is responding to a Frequency Measurable Event (FME) at or below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18, or under manual deployment when system frequency does not go below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18. Dispatch Instructions under this section shall only occur during scarcity conditions, as specified in Protocol Section 6.5.9.4.2, EEA Levels, or in an attempt to recover frequency to meet NERC Standards. |

(4) Unless ERCOT issues a recall instruction for the RRS deployed via Inter-Control Center Communications Protocol (ICCP), the QSE of the Generation Resource operating in synchronous condenser fast-response mode may contact ERCOT to determine if it is allowed to recall and reset the individual unit(s) to the synchronous condenser fast-response mode.

(5) ERCOT, at its sole discretion, may request that the Generation Resource operating in synchronous condenser fast-response mode remain On-Line and generating after an initial deployment. The request to remain On-Line and generating after an initial deployment may not exceed 30 minutes per deployment for each frequency deviation or event nor shall such request exceed two hours per a consecutive 12-hour period in aggregate unless ERCOT has declared an EEA.

(6) Load Resources providing RRS must be either a Controllable Load Resource qualified for SCED and capable of providing Primary Frequency Response or a Load Resource controlled by high-set under-frequency relays for automatic interruption. For eligibility to participate as a RRS provider, reference Protocol Section 8.1.1.2.1.2, Responsive Reserve Qualification. Load Resources controlled by high-set under-frequency relays shall also complete the following requirements:

(a) The under-frequency relay must have a delay of no more than 20 cycles (or 0.33 seconds for relays that do not count cycles). Total time from the time frequency first decays to a value low enough to initiate action of the under frequency relay(s) to the time Load is interrupted should be no more than 30 cycles, including all relay and breaker operating times;

(b) The initiation setting of the under-frequency relay shall not be any lower than 59.7 Hz; and

(c) The Load Resource must be able to remain interrupted during actual event until replaced by other net dependable capability. In no case may interrupted Load be restored to service without the approval of an ERCOT operator.

(7) To become and remain fully qualified as a provider of RRS, the Load Resource shall complete the requirements above and the following:

(a) Pass simulated or actual testing according to ERCOT procedures; and

(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.

(8) Generation Resource operating in synchronous condenser fast-response mode – Modes of RRS and/or ECRS that will be counted:

(a) Synchronous condenser fast response mode **-** described in item (3)(b) or (4)(c) of Protocol Section 3.18;

(b) Generation MW mode **-** For any Generation Resource with a 5% droop setting operating as a generator, the amount of RRS provided is dependent upon the verified droop characteristics of the Resource;

(c) Synchronous Condenser Mode in “Manual” Dispatch Mode - Units will supply MWs based on operator action within the ten-minute Protocol requirement for supplying RRS or ECRS. Once deployed these units are frequency responsive; and

(d) A Real-Time signal of the MW capacity of units being operated in any of the synchronous condenser modes is telemetered to ERCOT.

(9) Each Resource seeking RRS qualification as a Resource capable of providing FFR must be On-Line and shall also meet the following requirements:

(a) The total time from the time frequency first decays to a value low enough to initiate action up to the time when full Ancillary Service Resource Responsibility for RRS is delivered should be no more than 15 cycles, including all relay and breaker operating times;

(b) The initiation setting of the under-frequency relay or similar trigger mechanism shall not be any lower than 59.85 Hz;

(c) A Resource must demonstrate its ability to sustain the scheduled level of deployment for at least 15 minutes at a minimum level of 95% but not more than a maximum level of 110% of the MW capacity for which the Resource seeks qualification for FFR; and

(d) Resource providing FFR shall be capable of measuring and recording ERCOT Frequency (Hz) and MW output with a resolution of no less than 32 samples per second.

(10) Each QSE providing RRS with Resources capable of providing FFR shall so indicate by appropriate entries in the relevant Resources’ Ancillary Service Schedules and by setting the Ancillary Service Resource Responsibilities accordingly. Control performance during periods in which ERCOT has deployed FFR shall be based on the requirements below:

(a) For any FFR deployment event, ERCOT will collect the following data:

(i) High speed event data from Resources that are not deployed via breaker action;

(ii) High speed event data from the recorders at ERCOT’s primary and back-up facilities;

(iii) High speed event data from phasor measurement units available to ERCOT;

(iv) Telemetry data for all Resources providing FFR during the event; and

(v) Recording of ERCOT frequency (Hz) and MW output with a resolution of no less than 32 samples per second.

(b) The performance of a Load Resource providing FFR in response to an RRS Dispatch Instruction shall be determined by subtracting the Load Resource’s actual Load response from the average of the telemetered net real power consumption values for the five minutes preceding the Dispatch Instruction (“meter before / meter after”).  The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

(c) For an FFR deployment event triggered by an under-frequency event (frequency at or below 59.85 Hz). ERCOT will use the collected data to determine if the following requirements were met:

(i) The total time from the time frequency first decays to a value low enough to initiate action up to the time when full Ancillary Service Resource Responsibility for RRS is delivered should be no more than 15 cycles, including all relay and breaker operating times;

(ii) The Resource deployed 95% to 110% of its Ancillary Service Resource Responsibility in 15 cycles after the frequency reached 59.85 Hz;

(iii) The Resource sustained 95% to 110% of its Ancillary Service Resource Responsibility for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurred first;

(iv) The Resource restored its capability to provide its Ancillary Service Resource Responsibility within 15 minutes from the end of the deployment period subject to paragraph (v) below; and

(v) Upon completion of deployment, ERCOT will issue a recall instruction to a Resource providing FFR.  Once the recall instruction is issued to Resources providing FFR, it must ramp down to zero output level over the duration of five minutes.  A Resource providing FFR may withdraw energy from the grid only after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, unless ordered to do so by ERCOT.

(d) For an FFR deployment through a VDI, in addition to the data listed in paragraph (a) above, ERCOT will collect a voice recording of the VDI to document the time of the instruction.  The official start of the ramp period for the FFR deployment is the end of the ERCOT Operator’s acknowledgement that the read back of the instruction was correct.  ERCOT will use the collected data to determine if the following requirements were met:

(i) The Resource deployed 95% to 110% of its Ancillary Service Resource Responsibility within ten minutes after the start of the ramp period;

(ii) The Resource sustained 95% to 110% of its Ancillary Service Resource Responsibility for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurred first;

(iii) The Resource restored its capability to provide its Ancillary Service Resource Responsibility within 15 minutes after ERCOT declares that the EEA has been cancelled; and

(iv) Upon completion of deployment, ERCOT will issue a recall instruction to a Resource providing FFR.  A Resource providing FFR may withdraw energy from the grid only after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, unless ordered to do so by ERCOT.

(e) For a Resource providing FFR that is unable to return to its RRS Ancillary Service Resource Responsibility within 15 minutes from the end of the deployment period, its QSE may replace the quantity of deficient FFR capacity within that same 15 minutes using other Resources qualified to provide RRS but not already committed to provide RRS unless the Resource is not allowed by ERCOT to withdraw energy from the grid.

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| [NOGRR211: Replace paragraph (10) above with the following upon system implementation of NPRR1007:](10) Control performance during periods in which ERCOT has deployed FFR shall be based on the requirements below: (a) For any FFR deployment event, ERCOT will collect the following data:(i) High speed event data from Resources that are not deployed via breaker action; (ii) High speed event data from the recorders at ERCOT’s primary and back-up facilities;(iii) High speed event data from phasor measurement units available to ERCOT;(iv) Telemetry data for all Resources providing FFR during the event; and(v) Recording of ERCOT frequency (Hz) and MW output with a resolution of no less than 32 samples per second.  (b) The performance of a Load Resource providing FFR in response to an RRS Dispatch Instruction shall be determined by subtracting the Load Resource’s actual Load response from the average of the telemetered net real power consumption values for the five minutes preceding the Dispatch Instruction (“meter before / meter after”).  The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.(c) For an FFR deployment event triggered by an under-frequency event (frequency at or below 59.85 Hz). ERCOT will use the collected data to determine if the following requirements were met:(i) The total time from the time frequency first decays to a value low enough to initiate action up to the time when full Ancillary Service award for RRS is delivered should be no more than 15 cycles, including all relay and breaker operating times; (ii) The Resource deployed 95% to 110% of its Ancillary Service award for RRS in 15 cycles after the frequency reached 59.85 Hz;(iii) The SCED-dispatchable Resource sustained 95% to 110% of its Ancillary Service award for RRS;(iv) The non-Controllable Load Resource providing FFR sustained 95% to 110% of its Ancillary Service award for RRS for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurred first; (v) Upon completion of deployment, ERCOT will issue a recall instruction to a Resource providing FFR.  Once the recall instruction is issued to Resources providing FFR, the Resource shall continue following its Updated Desired Set Point (UDSP).  A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, or if instructed to do so by ERCOT.(d) For an FFR deployment of non-Controllable Load Resources through a VDI, in addition to the data listed in paragraph (a) above, ERCOT will collect a voice recording of the VDI to document the time of the instruction.  The official start of the ramp period for the FFR deployment is the end of the ERCOT Operator’s acknowledgement that the read back of the instruction was correct.  ERCOT will use the collected data to determine if the following requirements were met:(i) The Resource deployed 95% to 110% of its Ancillary Service award for RRS within ten minutes after the start of the ramp period;(ii) The Resource sustained 95% to 110% of its Ancillary Service award for RRS for the duration of the sustained response period, defined as 15 minutes or until the time of recall instruction from ERCOT, whichever occurred first; (iii) Upon completion of deployment, ERCOT will issue a recall instruction to a Resource providing FFR.  A Load Resource that is controlled by a high-set under-frequency relay and is providing FFR may only withdraw energy from the grid after the frequency has recovered to 60 Hz and Physical Responsive Capability (PRC) is above 2,500 MW, or if instructed to do so by ERCOT. |

(11) If a failure occurs at the QSE or sub-QSE level, as part of any compliance review ERCOT shall identify the individual Resource(s) responsible for the failure.  QSEs representing Resources providing FFR will have an opportunity to provide ERCOT with site-specific high resolution data (at least 32 samples per second) for further analysis.  Regardless of the QSE’s or sub-QSE level performance, ERCOT may require any individual Resource that fails to meet its FFR performance criteria to submit a corrective action plan and may suspend a Resource’s qualification to provide FFR for a pattern of non-performance.

2.3.1.2.1 Limit on Generation Resources and Controllable Load Resources Providing RRS

(1) ERCOT shall establish MW limits on individual Resource’s ability to provide RRS using Primary Frequency Response. The MW limit shall be based on Generating Resource and Controllable Load Resource performance during Frequency Measurable Events (FME).

(2) The default maximum MW limit of Primary Frequency Response shall be set to 20% of its High Sustained Limit (HSL) for any newly RRS-qualified Generation Resource or Generation Resource not yet evaluated per Section 8, Attachment N, Procedure for Calculating RRS Limits for Individual Resources, for measuring actual performance.

(3) A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide.

2.3.2 Non-Spinning Reserve Service

2.3.2.1 Additional Operational Details for Non-Spinning Reserve Service Providers

(1) Non-Spin Service Generation Resource providers must be capable of being synchronized and ramped to a specified output level within 30 minutes of notification of deployment and run at a specified output level for at least four consecutive hours, as specified in item (1)(a) of Protocol Section 3.17.3, Non-Spinning Reserve Service.

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| [NOGRR211: Replace paragraph (1) above with the following upon system implementation of NPRR1007:](1) Non-Spin Service Generation Resource providers, including MW from power augmentation, must be capable of being synchronized and ramped to a specified output level within 30 minutes of notification of deployment and run at a specified output level for at least four consecutive hours, as specified in item (1)(a) of Protocol Section 3.17.3, Non-Spinning Reserve Service. |

(2) Non-Spin Controllable Load Resource providers must be capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for at least four consecutive hours, as specified in item (1)(b) of Protocol Section 3.17.3.

(3) A Load Resource that is not a Controllable Load Resource providing Non-Spin must be capable of reducing Load based on an XML Dispatch Instruction issued by ERCOT within 30 minutes and maintaining that deployment until recalled.

(4) To become provisionally qualified as a provider of Non-Spin, a Load Resource shall complete the following requirements:

(a) Register as a Load Resource with ERCOT;

(b) Complete asset registration of the Load Resource;

(c) Provide ERCOT the appropriate Non-Spinning Load affidavit;

(d) Test to verify appropriate voice communications are in place for VDIs by ERCOT;

(e) Provide telemetry through the QSE to ERCOT in accordance with all applicable requirements set forth in paragraph (5) of Protocol Section 6.5.5.2, Operational Data Requirements; and

(f) Be able to consume at an ERCOT-instructed level during an ERCOT deployment based on the applicable duration requirements specified in Section 2.3, Ancillary Services.

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| [NOGRR211: Replace applicable portions of paragraph (4) above with the following upon system implementation of NPRR1007:](4) To become provisionally qualified as a provider of Non-Spin, a Load Resource shall complete the following requirements:(a) Register as a Load Resource with ERCOT;(b) Complete asset registration of the Load Resource;(c) Provide ERCOT the appropriate Non-Spinning Load affidavit;(d) Test to verify appropriate voice communications are in place for VDIs by ERCOT;(e) Provide telemetry through the QSE to ERCOT in accordance with all applicable requirements set forth in paragraph (5) of Protocol Section 6.5.5.2, Operational Data Requirements; and(f) Be able to consume at an ERCOT-instructed level during an ERCOT deployment based on the applicable duration requirements specified in Section 2.3, Ancillary Services. |

(5) To become and remain fully qualified as a provider of Non-Spin, the Load Resource shall complete all the requirements for provisional qualification identified above and the following:

(a) Respond successfully to an actual ERCOT deployment or pass simulated or actual testing according to ERCOT’s Procedure; and

(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.

2.3.3 ERCOT Contingency Reserve Service

2.3.3.1 Additional Operational Details for ERCOT Contingency Reserve Service (ECRS) Providers

(1) Generation Resources providing ECRS must be capable of being synchronized and ramped to a specified output level within ten minutes of notification of deployment and run at a specified output level for the entire duration of its ECRS obligation.

(2) Controllable Load Resource providing ECRS must be capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for the entire duration of its ECRS obligation.

(3) To become provisionally qualified as a provider of ECRS, a Controllable Load Resource shall complete the following requirements:

(a) Register as a Controllable Load Resource with ERCOT;

(b) Provide ERCOT the ECRS Load affidavit;

(c) Test to verify primary and alternative voice communications are in place for VDIs by ERCOT;

(d) Provide telemetry through the QSE to ERCOT in accordance with all applicable requirements set forth in paragraph (5) of Protocol Section 6.5.5.2, Operational Data Requirements; and

(e) Be able to maintain consumption at an ERCOT-instructed level during an ERCOT-instructed test for the entire duration of the test period.

(4) To become and remain fully qualified as a provider of ECRS, the Controllable Load Resource shall complete all the requirements for provisional qualification identified above and the following:

(a) Respond successfully to an actual ERCOT deployment or pass actual testing according to ERCOT’s Procedure; and

(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.

(5) The total amount of ECRS that Load Resources other than Controllable Load Resources may provide shall not exceed 50% of the total ERCOT-wide ECRS requirement. A Load Resource must be loaded and capable of unloading the scheduled amount of ECRS within ten minutes of instruction by ERCOT or be interrupted by action of under-frequency relays.

(a) Load Resources that are providing ECRS are not required to be controlled by high-set under-frequency relays.

(b) Load Resources controlled by high-set under-frequency relays and providing ECRS shall meet the relay setting requirement stated in paragraph (6) of Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers.

(6) ERCOT shall deploy ECRS to meet NERC Reliability Standards and other performance criteria as specified in these Operating Guides and the Protocols by one or more of the following:

(a) Automatic Dispatch Instruction signal to release ECRS capacity from Generation Resources and Controllable Load Resources to SCED; and/or

(b) Dispatch Instruction for deployment of Load Resources energy via electronic Messaging System.

(7) ERCOT shall release ECRS from Generation Resources and Controllable Load Resources to SCED when frequency drops below 59.91 Hz and available Reg-Up alone is not sufficient to restore frequency. ERCOT shall recall automatically deployed ECRS capacity once system frequency recovers above 59.97 Hz.

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| [NOGRR211: Replace Section 2.3.3.1 above with the following upon system implementation of NPRR1007:]2.3.3.1 Additional Operational Details for ERCOT Contingency Reserve Service (ECRS) Providers (1) Generation Resources providing ECRS must be capable of being synchronized and ramped to a specified output level within ten minutes of notification of deployment and run at a specified output level for at least two consecutive hours.(2) Controllable Load Resource providing ECRS must be capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for at least two consecutive hours. (3) To become provisionally qualified as a provider of ECRS, a Controllable Load Resource shall complete the following requirements:(a) Register as a Controllable Load Resource with ERCOT;(b) Provide ERCOT the ECRS Load affidavit;(c) Test to verify primary and alternative voice communications are in place for VDIs by ERCOT;(d) Provide telemetry through the QSE to ERCOT in accordance with all applicable requirements set forth in paragraph (5) of Protocol Section 6.5.5.2, Operational Data Requirements; and(e) Be able to maintain consumption at an ERCOT-instructed level during an ERCOT-instructed test for the entire duration of the test period.(4) To become and remain fully qualified as a provider of ECRS, the Controllable Load Resource shall complete all the requirements for provisional qualification identified above and the following:(a) Respond successfully to an actual ERCOT deployment or pass actual testing according to ERCOT’s Procedure; and(b) Perform verification testing as described in Section 8, Attachment G, Load Resource Tests.(5) The total amount of ECRS that Load Resources other than Controllable Load Resources may provide shall not exceed 50% of the total ERCOT-wide ECRS requirement. A Load Resource must be loaded and capable of unloading the scheduled amount of ECRS within ten minutes of instruction by ERCOT or be interrupted by action of under-frequency relays.(a) Load Resources that are providing ECRS are not required to be controlled by high-set under-frequency relays.(b) Load Resources controlled by high-set under-frequency relays and providing ECRS shall meet the relay setting requirement stated in paragraph (6) of Section 2.3.1.2, Additional Operational Details for Responsive Reserve Providers. (6) ERCOT shall deploy ECRS to meet NERC Reliability Standards and other performance criteria as specified in these Operating Guides and the Protocols by Dispatch Instruction for ECRS through Inter-Control Center Communications Protocol (ICCP) to a QSE representing a Generation Resource in synchronous condenser fast-response mode that is responding to a Frequency Measurable Event (FME) at or below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18, or under manual deployment when system frequency does not go below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18. Dispatch Instructions under this section shall only occur during scarcity conditions, as specified in Protocol Section 6.5.9.4.2, EEA Levels, or in an attempt to recover frequency to meet NERC Standards; and/or Dispatch Instruction for deployment of Load Resources energy via electronic Messaging System. |

2.4 Outage Coordination

(1) For Outage coordination details, reference Protocol Section 3.1, Outage Coordination and the ERCOT Market Information System (MIS) Secure Area.

2.5 Reliability Unit Commitment

2.5.1 Criteria for Removing Contingencies from the Reliability Unit Commitment Analyses

(1) ERCOT shall remove contingencies from the Reliability Unit Commitment (RUC) analysis when:

(a) The contingency is known to produce post-contingency results that are incorrect; or

(b) The contingency is known to produce a non-convergent contingency result which may cause the RUC process to fail.

2.6 Requirements for Under-Frequency and Over-Frequency Relaying

2.6.1 Automatic Firm Load Shedding

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, below. TOs may, but are not required to, provide supplemental anti-stall under-frequency Load relief in the amounts described in Table 2, Supplemental Anti-Stall UFLS Stages, below. If the TOs provide supplemental anti-stall under-frequency Load relief, the under-frequency relays shall be set to use the frequency thresholds and time delays described in Table 2. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO’s transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

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| ***[NOGRR226: Replace paragraph (1) above with the following upon system implementation but no earlier than October 1, 2026:]***(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, and Table 2, Supplemental/Anti-Stall UFLS Stages, below. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO’s transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.  |

Table 1: Standard UFLS Stages

|  |  |  |
| --- | --- | --- |
| **Frequency Threshold** | **TO Load Relief** | **Delay to Trip** |
| 59.3 Hz | At least 5% of the TO Load | No more than 30 cycles |
| 59.1 Hz | A total of at least 5% of the TO Load | No more than 30 cycles |
| 58.9 Hz | A total of at least 15% of the TO Load | No more than 30 cycles |
| 58.7 Hz | A total of at least 15% of the TO Load | No more than 30 cycles |
| 58.5 Hz | A total of at least 25% of the TO Load | No more than 30 cycles |
| ***[NOGRR247: Replace Table 1 above with the following upon system implementation but no earlier than October 1, 2026:]***

|  |  |  |
| --- | --- | --- |
| **Frequency Threshold** | **TO Load Relief** | **Delay to Trip** |
| 59.3 Hz | At least 5% of the TO Load | At least six cycles but no more than 30 cycles |
| 59.1 Hz | A total of at least 10% of the TO Load | At least six cycles but no more than 30 cycles |
| 58.9 Hz | A total of at least 15% of the TO Load | At least six cycles but no more than 30 cycles |
| 58.7 Hz | A total of at least 20% of the TO Load | At least six cycles but no more than 30 cycles |
| 58.5 Hz | A total of at least 25% of the TO Load | At least six cycles but no more than 30 cycles |

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Table 2: Supplemental/Anti-Stall UFLS Stages

|  |  |  |
| --- | --- | --- |
| **Frequency Threshold** | **TO Load Relief** | **Delay to Trip** |
| 59.5 Hz | At least 1.5% of the TO Load | 90 seconds |
| 59.5 Hz | A total of at least 3.0% of the TO Load | 120 seconds |
| 59.5 Hz | A total of at least 4.5% of the TO Load | 150 seconds |

(2) ERCOT will, prior to the peak each year, survey each TO’s compliance with the automatic Load shedding requirements described in paragraph (1) above, and report its findings to the Technical Advisory Committee (TAC). For purposes of determining a TO’s compliance with this annual survey requirement, TO Load will be the total amount of Load being served by the DSPs that the TO represents, as well as the TO’s transmission-level Customer Load, at the specified time of the survey. The TO shall identify those circuits armed with under-frequency relays, the corresponding amount of Load, and identify the frequency threshold. A TO shall not equip the entirety of its Load shed obligation in any one tier, and should endeavor to shed in controlled amounts that equal the difference between the TO Load relief required for each tier. If ERCOT identifies potential reliability issues related to distribution of Load shed across the tiers, ERCOT may require the TO to redistribute Load relief closer to the minimum amount required after submitting ERCOT’s proposal to redistribute Load relief to the TO and considering any comments submitted by the TO regarding the proposal. Compliance with this annual survey does not excuse the TO from compliance with the requirements of paragraph (1) above in an actual frequency event. To assist TOs, ERCOT will provide the TO’s inventory, including substation and capacity amounts, of registered Load Resources in its area within ten Business Days of receiving a request in writing from a TO.

(3) A TO may meet the Load relief requirements of the Supplemental anti-stall UFLS stages by utilizing Load that would otherwise be utilized to meet the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages. In this circumstance, the TO’s Load relief responsibility at the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages is reduced by the amount of Load already shed in the supplemental anti-stall UFLS stages. A TO may not meet the Load relief requirements of the supplemental anti-stall UFLS stages by utilizing Load that the TO needs to meet the 59.3 Hz standard UFLS stages.

(4) Additional under-frequency relays may be installed on Transmission Facilities with the approval of ERCOT provided the relays are set at 58.0 Hz or below, are not directional, and have at least 2.0 seconds time delay. A DSP may by mutual agreement arrange to have all or part of its automatic Load shedding requirement performed by another entity. ERCOT will be notified and provided with the details of any such arrangement prior to implementation.

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) are connected to circuits that are not subject to disconnection during UFLS events, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs). DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

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| ***[NOGRR250: Replace paragraph (5) above with the following upon system implementation of NPRR1171:]***(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation. |

(6) If a loss of Load occurs due to the operation of under-frequency relays, a DSP or its designee may rotate the physical Load interrupted to minimize the duration of interruption experienced by individual Customers or to restore the availability of under-frequency Load-shedding capability. In no event shall the initial total amount of Load without service be decreased without the approval of ERCOT. TOs, in coordination with DSPs, shall make every reasonable attempt to restore Load, either by automatic or manual means, to preserve system integrity. Restoration of any Load shed by UFLS systems, including supplemental anti-stall UFLS Load, shall be coordinated with ERCOT by the TO. In the event frequency drops below any of the frequency thresholds specified in the tables in paragraph (1) above, and a TO’s UFLS relays that previously activated as a result of reaching that same frequency threshold have not been restored since the previous excursion, the Load on the feeders controlled by those relays shall be counted toward the TO’s satisfaction of the percentages in paragraph (1) above for that subsequent frequency excursion.

2.6.2 Generators and Energy Storage Resources

(1) Except for Generation Resources subject to Section 2.6.2.1, Frequency Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs), if under-frequency relays are installed and activated to trip the Generation Resource, these relays shall be set such that the automatic removal of individual Generation Resources or Energy Storage Resources (ESRs) from the ERCOT System meets or exceeds the following requirements:

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| --- | --- |
| **Frequency Range** | **Delay to Trip** |
| Above 59.4 Hz | No automatic tripping(Continuous operation) |
| Above 58.4 Hz up toAnd including 59.4 Hz | Not less than 9 minutes |
| Above 58.0 Hz up toAnd including 58.4 Hz | Not less than 30 seconds |
| Above 57.5 Hz up toAnd including 58.0 Hz | Not less than 2 seconds |
| 57.5 Hz or below | No time delay required |

(2) Except for Generation Resources subject to Section 2.6.2.1, if over-frequency relays are installed and activated to trip the unit, they shall be set such that the automatic removal of individual Generation Resources or ESRs from the ERCOT System meets or exceeds the following requirements:

|  |  |
| --- | --- |
| **Frequency Range** | **Delay to Trip** |
| Below 60.6 Hz down to and including 60 Hz | No automatic tripping (Continuous operation) |
| Below 61.6 Hz down to and including 60.6 Hz | Not less than 9 minutes |
| Below 61.8 Hz down to and including 61.6 Hz | Not less than 30 seconds |
| 61.8 Hz or above | No time delay required |

(3) This Operating Guide is not intended to conflict with the plant operator’s responsibility to protect Generation Resources and ESRs from potentially damaging operating conditions.

(4) The Resource Entity that owns Generation Resources that are unable to comply shall provide to ERCOT an explanation of the limitations including, but not limited to, study results or manufacturer’s advice.

**2.6.2.1 Frequency Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)**

(1) For any short-circuit fault or open-phase condition that occurs on the circuit to which the DGR or DESR is connected, the DGR or DESR will cease to energize and trip offline, and this will take priority over the frequency ride-through function.

(2) DGRs and DESRs must have over-/under-frequency relays set to ride through frequency conditions as specified in the following table:

|  |  |  |
| --- | --- | --- |
| Frequency (Hz) | Ride-Through Mode | Minimum Ride-through Time(seconds) |
|  *f > 61.8* | No ride-through requirements |
| 61.2 < f ≤ 61.8 | Mandatory Operation | 299 |
| 58.8 ≤ f ≤ 61.2 | Continuous Operation | continuous |
| 57.0 ≤ f < 58.8 | Mandatory Operation | 299 |
| *f < 57.0* | No ride-through requirements |

(3) Any Resource Entity with a DGR or DESR utilizing inverter-based generation that achieved Initial Synchronization before April 1, 2020 that is not capable of complying with the requirements of paragraph (2) above may request an exemption from those requirements. Such a request shall be submitted by November 2, 2020 and shall include documentation that demonstrates the DGR’s or DESR’s frequency ride-through capability to ERCOT’s satisfaction. If, after reviewing the request and documentation, ERCOT determines the DGR or DESR is not capable of complying with the requirements of paragraph (2), then the DGR or DESR shall be exempt from those requirements, but shall be required to comply with those requirements to the greatest degree possible within its capability, as determined in writing by ERCOT. Upon replacement or retirement of the inverter, the DGR or DESR shall no longer be exempt and shall at that time be required to comply with the requirements of paragraph (2) or other applicable requirement.

***2.6.3 Frequency Ride-Through Requirements for Direct Current Ties (DC Ties)***

(1) The following Direct Current Ties (DC Ties) are subject to the frequency ride-through requirements specified in this Section:

(a) Any DC Tie with an initial energization date after January 1, 2021.

(b) Any DC Tie that is modified by increasing the physical capacity of the DC Tie by 20 MW or more or by changing the power converter associated with the DC Tie, unless the replacement is in-kind.

(2) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure the DC Tie rides through the frequency conditions specified in the following table:

|  |  |
| --- | --- |
| Frequency (Hz) | Minimum Ride-Through Time(seconds) |
|  *f >* 61.8 | No ride-through requirements |
| 61.2 < f ≤ 61.8 | 299 |
| 58.8 ≤ f ≤ 61.2 | continuous |
| 57.0 ≤ f < 58.8 | 299 |
| *f <* 57.0 | No ride-through requirements |

(3) Nothing in paragraph (2) above shall be interpreted to require a DC Tie to trip for frequency conditions beyond those for which ride-through is required.

(4) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure any protective over- or under-frequency relay for the DC Tie is set to enable the DC Tie to ride through any frequency condition beyond those defined in paragraph (2) above to the maximum extent possible within the DC Tie’s capability.

2.7 System Voltage Profile and Operational Voltage Control

2.7.1 Introduction

(1) The system Voltage Profile is the set of normally desired Voltage Set Points for those Generation Resources and Energy Storage Resources (ESRs) required to provide Voltage Support Service (VSS).

(2) ERCOT coordinates and conducts studies with the Transmission Service Providers (TSPs) to determine and establish the Voltage Profile.

(3) ERCOT and/or the Transmission Operators (TOs) adjust Voltage Set Points to maintain system voltages within established limits.

2.7.2 Maintaining Voltage Profile

(1) ERCOT has the responsibility for monitoring and controlling the Voltage Profile and should use the following:

(a) Operations Engineering

(i) All voltage limits must be based on sound engineering studies that use the appropriate Network Operations Model. TSP study results should be made available to ERCOT; and

(ii) Transfer limits shall reflect voltage and/or reactive restrictions.

(b) Coordination

(i) Entities must coordinate high voltage limits in order to guarantee that the maximum continuous over-voltage of equipment is not exceeded. TOs shall notify ERCOT of normal operating voltage limits and post-contingency voltage limits for each bus;

(ii) Low voltage limits must be coordinated in order to prevent one Entity from being a burden to another;

(iii) Voltage limits shall not be violated during all normal and Credible Single Contingency conditions; and

(iv) The operation of all Reactive Power devices under the control of a TO or a Qualified Scheduling Entity (QSE) will be coordinated under the direction of ERCOT to maintain transmission voltage levels within normal limits and post-contingency voltages within post contingency limits. Static reactive devices will be managed to ensure that adequate dynamic reactive reserves are maintained at all times.

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| [NOGRR234: Replace item (iv) above with the following upon system implementation of NPRR1098:](iv) The operation of all Reactive Power devices under the control of a TO, Direct Current Tie Operator (DCTO), or a Qualified Scheduling Entity (QSE) will be coordinated under the direction of ERCOT to maintain transmission voltage levels within normal limits and post-contingency voltages within post contingency limits. Static reactive devices will be managed to ensure that adequate dynamic reactive reserves are maintained at all times. |

(c) Notification

(i) Generation Resources or ESRs with voltage problems shall notify the TO to whom they are directly connected. TOs shall notify other affected TOs and ERCOT; and

(ii) ERCOT will monitor events and may direct actions to solve the problem.

(d) Response

(i) When the voltage levels deviate from established limits, ERCOT or the TO shall take immediate steps to relieve the condition using all available reactive resources.

(e) Monitoring

(i) TOs shall provide telemetry to ERCOT on all major transmission bus voltages.

(f) Controls

(i) ERCOT must be aware of the location of and availability of reactive capability;

(ii) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows; and

(iii) Controls to maintain Voltage Profiles may include but are not limited to capacitor switching, reactor switching, auto-transformer tap changing, Generation Resource and ESR reactive dispatch, transmission line switching, and Load shedding.

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| [NOGRR234: Replace item (f) above upon system implementation of NPRR1098:](f) Controls(i) ERCOT must be aware of the location of and availability of reactive capability;(ii) ERCOT shall maintain displays to monitor Voltage Profiles and reactive flows; and(iii) Controls to maintain Voltage Profiles may include but are not limited to capacitor switching; reactor switching; auto-transformer tap changing; Generation Resource, ESR, and Direct Current Tie (DC Tie) reactive dispatch; transmission line switching; and Load shedding. |

(g) Documentation

(i) Each TO must maintain a voltage/reactive plan for normal and Emergency Conditions and will provide this plan to adjacent TOs as well as ERCOT upon request.

(h) Emergency or Abnormal Conditions

(i) Transmission systems shall be designed so that effective reactive reserves shall be available without de-energizing other Facilities or shedding Load under normal conditions;

(ii) Major transmission lines shall be kept in service during light Load as much as possible. Lines should only be removed after all applicable reactive controls are implemented and studies show that reliability will not be degraded; and

(iii) Voltage reduction should not be done on the transmission system unless coordinated with adjacent TOs.

2.7.3 Real-Time Operational Voltage Control

**2.7.3.1 Operational Guidelines**

(1) The following guidelines describe ideal system operational characteristics and do not establish requirements for any particular Entity:

(a) General operational voltage limits are:

|  |  |  |
| --- | --- | --- |
| Nominal Voltage | Normal Operating Limits | Emergency Operating Limits |
| 345 | 327.75 – 362.25 | 310.5 – 379.5 |
| 230 | 218.5 – 241.5 | 207 – 253 |
| 138 | 131.1 – 144.9 | 124.2 – 151.8 |
| 115 | 109.25 – 120.75 | 103.5 – 126.5 |
| 69 | 65.55 – 72.45 | 62.1 – 75.9 |

(b) Except for Transmission Facilities that are designed to operate outside of normal operating limits, transmission voltage should not exceed 105% nor fall below 95% of the nominal voltage during normal operation of the system.

(c) Transmission voltage during emergencies (including contingency events) should not exceed equipment over-excitation ratings.

(d) Transmission voltage during emergencies (including contingency events) should not result in customer voltage exceeding or falling below prescribed limits at distribution substations on the transmission system.

(e) Transmission voltage post contingency should not exceed 110% nor fall below 90% of the per-unit voltage, unless more restrictive limits have been specified by the TSP for their system, then those limits shall not be exceeded.

(f) Transmission voltage post contingency should not fall below any Under-Voltage Load Shedding (UVLS) set point during normal operations.

(g) The accuracy of any transmission voltage that appears to exceed normal or emergency limits should be verified prior to taking further actions.

(h) Major transmission lines should be kept in service during light Load as much as possible. Lines should only be removed after all applicable reactive controls are implemented and the practicality of additional generation Dispatch has been considered. Time permitting, studies should be conducted to verify that reliability will not be degraded by removing any major transmission line from service.

(i) Generally speaking, static reactive devices should be brought On-Line before predicted daily maximum Load or before dynamic reactive Resources reach operating limits. Static reactive devices will be taken Off-Line during daily Load decline and before dynamic reactive Resources reach operating limits.

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) Re-dispatching 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 buses, 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 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.

(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 or 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 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.

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| ***[NOGRR177 and NOGRR234: Replace applicable portions of Section 2.7.3.3 above with the following upon system implementation of NPRR857 or NPRR1098, respectively:]***2.7.3.3 TO/TSP 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 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. (8) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator (DCTO) Responsibilities Related to Voltage Support, shall be responsible for directing the operation of reactive power resources operated by that DCTO. Each TO shall telemeter to ERCOT via ICCP and to the DCTO via telemetry, the Real-Time desired target voltage at the DC Tie’s Point of Interconnection Bus (POIB) and the actual voltage at the POIB. Each TO shall modify the telemetered target voltage to match any verbal target voltage instruction issued as soon as practicable.(9) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4 shall for each such DC Tie provide to ERCOT, via ICCP, the status of the DC Tie Facility’s voltage control system. An “On” status will indicate that the control system is on and set to regulate the voltage at the DC Tie’s POIB in automatic voltage control mode, and an “Off” status will indicate that the control system is off or in manual mode.(10) Each TO designated by a DCTO operating a DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4 shall, as soon as practicable, notify ERCOT when a DC Tie Facility experiences a change that affects its reactive capability, including any change to the operation mode of the DC Tie Facility’s voltage control system or any temporary transmission voltage limit changes. |

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, via telemetry and verbal notifications, 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. For each Generation Resource that is On-Line but not producing real power and is not capable of providing Reactive Power, each QSE must still telemeter its AVR status to ERCOT, but is not required to provide verbal notifications of its AVR status changes to ERCOT during these operating conditions.

2.7.3.5 Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements

(1) Each Resource Entity shall ensure that its Generation Resource(s) and ESR(s) responds to all VSS Dispatch Instruction or a TO Voltage Set Point instruction from its QSE or interconnecting TO 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) below.

(2) Generation Resources or ESRs with high reactive loading resulting from abnormal conditions shall not reduce their reactive loading without the consent of ERCOT unless equipment damage is imminent based on the sole and reasonable judgment of the Resource Entity. In that case the Resource Entity will notify its QSE and its TO as soon as practicable of its action.

(3) Each Resource Entity shall monitor Real-Time provided Voltage Set Point instructions it receives. The Resource Entity shall inform its QSE and either the Resource Entity or its QSE shall notify the Resource Entity’s TO, as soon as practicable, but not longer than 15 minutes from receipt of the instruction by the Resource Entity, if it cannot comply with TO Voltage Set Point instructions, or not longer than 30 minutes from being outside of the tolerance band if it cannot maintain the POIB voltage within the tolerance band identified in paragraph (4) below. If a Resource Entity cannot comply with a VSS Dispatch Instruction, the Resource Entity shall inform its QSE and its QSE shall notify ERCOT as soon as practicable but not longer than 15 minutes from the receipt of the instruction by the Resource Entity.

(4) A Resource Entity required to provide VSS shall maintain the Resource’s voltage or Reactive Power schedule to maintain voltage at the POIB to be within a tolerance band of the Voltage Set Point while operating at less than or equal to the maximum reactive capability of the Generation Resource or ESR. A Generation Resource’s or ESR’s POIB voltage may be out of the tolerance band if it has exhausted all of its reactive capability. The tolerance bands are as follows:

|  |  |
| --- | --- |
| Nominal Voltage | Tolerance Band kV |
| 345 | +/- 4kV |
| 230 | +/- 3kV |
| 138 | +/- 2kV |
| 115 | +/- 2kV |
| 69 | +/- 1kV |

(5) Required reactive capability must be maintained at all times that the Generation Resource or ESR is On-Line. When a Generation Resource or ESR experiences a change that affects its reactive capability, the associated Resource Entity shall notify its QSE and TO, as soon as practicable but not longer than 30 minutes from becoming aware of the change in reactive capability.

(6) Each Resource Entity shall communicate any Resource Entity-owned transmission voltage limits that deviate from those identified in Section 2.7.3.1, Operational Guidelines, to ERCOT and to its QSE.

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| [NOGRR234: Insert Section 2.7.3.6 below upon system implementation of NPRR1098:]**2.7.3.6 DCTO Responsibilities and DC Tie Requirements**(1) Each DCTO operating a DC Tie subject to Protocol Section 3.15.4, Direct Current Tie Owner and Direct Current Tie Operator Responsibilities Related to Voltage Support, shall comply with any instruction from its designated TO with respect to the DC Tie’s Reactive Power capability, including any instruction to maintain a specific voltage at the POIB, subject to the DC Tie’s operating characteristic limits and voltage limits, and within the tolerances identified in paragraph (2) below, and subject to any superseding Dispatch Instruction from ERCOT.(2) A DCTO operating a DC Tie subject to Protocol Section 3.15.4 shall maintain the voltage at the POIB within the tolerance band below while operating at less than or equal to the maximum reactive capability of the DC Tie. A DC Tie’s POIB voltage may be out of the tolerance band if all of its reactive capability has been exhausted. The tolerance bands are as follows:

|  |  |
| --- | --- |
| Nominal Voltage | Tolerance Band kV |
| 345 | +/- 4kV |
| 230 | +/- 3kV |
| 138 | +/- 2kV |
| 115 | +/- 2kV |
| 69 | +/- 1kV |

(3) Required reactive capability must be maintained at all times that the DC Tie is not experiencing an Outage. When a DC Tie experiences a change that affects its reactive capability, the associated DCTO shall notify its TO as soon as practicable, but not longer than 30 minutes, from becoming aware of the change in reactive capability.(4) Each DCTO shall, as soon as practicable, notify its TO of any temporary transmission voltage limit changes. The DC Tie owner shall coordinate with its DCTO on necessary changes to the Network Operations Model. The DCTO will 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.(5) Each DCTO shall provide to its TO, via telemetry, the status of the voltage control system for any DC Tie meeting the applicability requirements of paragraph (1) of Protocol Section 3.15.4. An “On” status will indicate that the control system is on and set to regulate the voltage at the DC Tie’s POIB in automatic voltage control mode, and an “Off” status will indicate that the control system is off or in manual mode.  |

2.7.4 Special Consideration for Nuclear Power Plants

(1) In all planning studies and Real-Time operations, ERCOT and TOs shall maintain the switchyard voltage at each nuclear power plant at a value that does not violate its licensing basis with the Nuclear Regulatory Commission (NRC) ERCOT shall notify the QSE representing a nuclear power plant of the result of any studies where the voltage at the plant switchyard cannot be adequately maintained. ERCOT and the TO shall monitor the voltage in Real-Time. ERCOT shall provide notice to the QSE representing the nuclear power plant of any voltage inadequacy at the plant switchyard that cannot be corrected within 30 minutes. High and low limits on switchyard voltage at each nuclear power plant necessary to meet these requirements shall be specified in ERCOT Procedures.

*2.7.5 Parameters for Standard Reactor and Capacitor Switching Plan*

(1) TOs shall provide switching plans for automatically controlled reactors, capacitors, and other reactive controlled sources to ERCOT. For manually switched reactive devices, the TO shall provide its guidelines for the operation of these devices. These plans and guidelines shall be posted on the Market Information System (MIS) Secure Area and must be provided in accordance with the NOMCR or other ERCOT prescribed process. The parameters to be provided in the standard reactor and capacitor switching plan as required by Protocol Section 3.10.7.1.5, Reactors, Capacitors, and other Reactive Controlled Sources, are as follows:

**Device Attributes**

(a) Transmission Element name per Protocol Section 3.10.7.1, Modeling of Transmission Elements and Parameters;

(b) Substation name; and

(c) Schedules of device:

(i) Time-based;

(ii) Voltage-based;

(iii) Load-based;

(iv) Contingency-based;

(v) Normal Operation;

(vi) Emergency Operation;

(vii) Seasonal; and

(viii) Others as required by technology.

*2.7.6 Unit Dispatch Beyond the Corrected Unit Reactive Limit or Unit Reactive Limit*

(1) Each Generation Resource shall respond to ERCOT instructed voltage control, including exceeding its CURL or URL. For multi-generator buses, ERCOT shall not instruct any single Generation Resource to operate beyond its CURL or URL until all Generation Resources On-Line and interconnected at the same transmission bus, have been instructed to their respective CURLs or URLs.

2.8 Operation of Direct Current Ties

(1) ERCOT will confirm interconnected non-ERCOT balancing authority schedule profiles with the Direct Current Tie (DC Tie) operator, who will control the tie to the schedules agreed to by both the designated security coordinator for the interconnected non-ERCOT balancing authority and ERCOT.

(2) Any changes in the DC Tie schedules due to a de-rating of the DC Tie or transmission/generation capabilities in the non-ERCOT balancing authority will be communicated to ERCOT by the DC Tie Operator or designated security coordinator for the interconnected non-ERCOT balancing authority.

(3) ERCOT will coordinate operation of the DC Tie(s) with the DC Tie operator such that the Inadvertent Energy Account as defined in Protocol Section 6.5.4, Inadvertent Energy Account, is maintained as close to zero as practicable.

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| ***[NOGRR177: Replace Section 2.8 above with the following upon system implementation of NPRR857:]***2.8 Operation of Direct Current Ties(1) ERCOT will confirm interconnected non-ERCOT balancing authority schedule profiles with the Direct Current Tie Operator (DCTO), who will control the tie to the schedules agreed to by both the designated security coordinator for the interconnected non-ERCOT balancing authority and ERCOT. (2) Any changes in the DC Tie schedules due to a de-rating of the DC Tie or transmission/generation capabilities in the non-ERCOT balancing authority will be communicated to ERCOT by the DCTO or designated security coordinator for the interconnected non-ERCOT balancing authority.(3) ERCOT will coordinate operation of the Direct Current Tie(s) (DC Tie(s)) with the DCTO such that the Inadvertent Energy Account as defined in Protocol Section 6.5.4, Inadvertent Energy Account, is maintained as close to zero as practicable.  |

2.8.1 Inadvertent Energy Management

(1) The only inadvertent energy will be between ERCOT and the Southwest Power Pool (SPP) and/or Comision Federal de Electricidad (CFE). ERCOT shall track any differences between the net of scheduled energy across each DC Tie and the actual metered value at that DC Tie in an Inadvertent Energy Account between ERCOT and each interconnected non-ERCOT balancing authority as per Protocol Section 6.5.4, Inadvertent Energy Account. All inadvertent energy is placed in an inadvertent payback account to be paid back in kind.

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| [NOGRR177: Replace Section 2.8.1 above with the following upon system implementation of NPRR857:]2.8.1 Inadvertent Energy Management  (1) The only inadvertent energy will be between ERCOT and non-ERCOT Control Areas. ERCOT shall track any differences between the net of scheduled energy across each DC Tie and the actual metered value at that DC Tie in an Inadvertent Energy Account between ERCOT and each interconnected non-ERCOT balancing authority as per Protocol Section 6.5.4, Inadvertent Energy Account. All inadvertent energy is placed in an inadvertent payback account to be paid back in kind.  |

2.9 Voltage Ride-Through Requirements for Generation Resources and Energy Storage Resources

(1) Except for Generation Resources subject to Sections 2.9.1, Voltage Ride-Through Requirements for Intermittent Renewable Resources and Energy Storage Resources Connected to the ERCOT Transmission Grid, and 2.9.2, Voltage Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs), each Generation Resource and Energy Storage Resource (ESR) must be designed, and its voltage relays must be set, to remain connected to the transmission system during the following operating conditions:

(a) Generator or inverter terminal voltages are within 5% of the rated design voltage and volts per hertz are less than 105% of generator rated design voltage and frequency;

(b) Generator or inverter terminal voltage deviations exceed 5% but are within 10% of the rated design voltage and persist for less than ten seconds;

(c) Generator or inverter volts per hertz conditions are less than 116% of rated design voltage and frequency and last for less than 1.5 seconds; and

(d) A transmission system fault (three-phase, single-phase or phase-to-phase), but not a unit bus fault, is cleared by the protection scheme coordinated between the Resource Entity and the Transmission Service Provider (TSP) on any line connected to the Resource’s Point of Interconnection (POI), provided such lines are not connected to induction generators described in paragraph (12) of Protocol Section 3.15, Voltage Support.

(2) In the case of a unit bus fault or a primary transmission system relay failure, the unit protective relaying may clear the unit independent of the operation of any transmission protective relaying.

(3) During operating conditions listed in paragraph (1) above, each Generation Resource or ESR shall not, during and following a transient voltage disturbance, cease providing real or reactive power except to the extent needed to provide frequency support or aid in voltage recovery. Each ESR, if it is consuming active power from the ERCOT System when operating in the charging mode, shall reduce or cease power consumption as necessary to aid in voltage recovery during and following transient voltage disturbances.

(4) Synchronous Generation Resources required to provide Voltage Support Service (VSS) shall have and maintain the following capability:

(a) Over-excitation limiters shall be provided and coordinated with the thermal capability of the generator field winding and protective relays in order to permit short-term reactive capability that allows at least 80% of the unit design standard (ANSI C50.13-1989), as follows:

Time (seconds) 10 30 60 120

Field Voltage % 208 146 125 112

After allowing temporary field current overload, the limiter shall operate through the automatic AC voltage regulator to reduce field current to the continuous rating. Return to normal AC voltage regulation after current reduction shall be automatic. The over-excitation limiter shall be coordinated with the over-excitation protection so that over-excitation protection only operates for failure of the voltage regulator/limiter.

(b) Under-excitation limiters shall be provided and coordinated with loss-of-field protection to eliminate unnecessary generating unit disconnection as a result of operator error or equipment malfunction.

(5) Generation Resources and ESRs shall have protective relaying necessary to protect their equipment from abnormal conditions as well as to be consistent with protective relaying criteria described in Section 6.2.6.3.4, Generation and Energy Storage Resource Protection and Relay Requirements.

(6) The voltage ride-through requirements do not apply to faults that occur at or behind the POI, or when clearing the fault effectively disconnects the Resource from the ERCOT System.

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 voltage ride-through 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 voltage ride-through 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 voltage ride-through 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 voltage ride-through requirements presented in this Section. However, any Wind-powered Generation Resource (WGR) that is installed on or after November 1, 2008 and that initially synchronizes with the ERCOT System, pursuant to an 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 voltage ride-through-capable in accordance with the low voltage ride-through 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 voltage ride-through 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 voltage ride-through 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 voltage ride-through requirement greater than 1.1 per unit voltage until January 16, 2016.

(d) Notwithstanding any of the foregoing provisions, an IRR’s voltage ride-through capability shall not be reduced over time.

(2) Each IRR or ESR shall provide technical documentation of voltage ride-through 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 Connected to the ERCOT Transmission Grid, 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 Bus (POIB) unless a shorter clearing time requirement for a three-phase fault specific to the POIB 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 POIB.

(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) Voltage ride-through 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. Voltage ride-through 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 voltage ride-through 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.

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

***2.9.2 Voltage Ride-Through Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs)***

(1) For any short-circuit fault or open-phase condition that occurs on the distribution circuit to which the DGR or DESR is connected, the DGR or DESR will cease to energize and trip offline, and will take priority over the voltage ride-through function.

(2) DGRs utilizing synchronous generation must have over-/under-voltage relays set to ride through the following operating conditions:

|  |  |
| --- | --- |
| Voltage (p.u. of nominal) | Minimum Ride-Through Time(seconds) |
| 0.88 < *V* < 1.10 | continuous |
| 0.70 < *V* < 0.88 | Linear slope of 4 s/1 p.u. voltage starting at 0.7 s @ 0.7 p.u. |

(3) DGRs and DESRs utilizing inverter-based generation must be designed and relays must be set to ride through the following operating conditions:

|  |  |  |
| --- | --- | --- |
| Voltage (p.u. of nominal) | Ride-Through Mode  | Minimum Ride-Through Time(seconds) |
| 1.10 < *V* < 1.20 | Momentary Cessation | 12 |
| 0.88 < *V* < 1.10 | Continuous Operation | continuous |
| 0.70 < *V* < 0.88 | Mandatory Operation | 20 |
| 0.50 < *V* < 0.70 | Mandatory Operation | 10 |
| *V* < 0.50 | Momentary Cessation | 1 |

(4) Any Resource Entity with a DGR or DESR utilizing inverter-based generation that achieved Initial Synchronization before August 1, 2020 that is not capable of complying with the requirements of paragraph (3) above may request an exemption from those requirements. Such a request shall be submitted by November 2, 2020 and shall include documentation that demonstrates the DGR’s or DESR’s voltage ride-through capability to ERCOT’s satisfaction. If, after reviewing the request and documentation, ERCOT determines the DGR or DESR is not capable of complying with the requirements of paragraph (3), then the DGR or DESR shall be exempt from those requirements, but shall be required to comply with those requirements to the greatest degree possible within its capability, as determined in writing by ERCOT. Upon replacement or retirement of the inverter, the DGR or DESR shall no longer be exempt and shall at that time be required to comply with the requirements of paragraph (3) or other applicable requirement.

**2.10 Voltage Ride-Through Requirements for DC Ties**

(1) The following Direct Current Ties (DC Ties) are subject to the voltage ride-through requirements specified in this Section:

(a) Any DC Tie with an initial energization date after January 1, 2021.

(b) Any DC Tie that is modified by increasing the physical capacity of the DC Tie by 20 MW or more or by changing the power converter associated with the DC Tie, unless the replacement is in-kind.

(2) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure the DC Tie rides through the root-mean-square voltage conditions specified in Table A and the instantaneous phase voltage conditions specified in Table B, as measured at the DC Tie’s Point of Interconnection Bus (POIB):

**Table A**

|  |  |
| --- | --- |
| Root-Mean-Square Voltage (p.u. of nominal) | Minimum Ride-Through Time(seconds) |
| V > 1.20 | No ride-through requirements |
| 1.10 < V ≤ 1.20 | 1.0 |
| 0.90 ≤ V ≤ 1.10 | continuous |
| 0.70 ≤ V < 0.90 | 6.0 |
| 0.50 ≤ V < 0.70 | 3.0 |
| 0.25 ≤ V < 0.50 | 1.2 |
| V < 0.25 | 0.16 |

**Table B**

|  |  |
| --- | --- |
| Instantaneous Phase Voltage(p.u. of nominal) | Minimum Ride-Through Time(milliseconds) |
| V > 1.80 | No ride-through requirements |
| 1.70 < V ≤ 1.80 | 0.2 |
| 1.60 < V ≤ 1.70 | 1.0 |
| 1.40 < V ≤ 1.60 | 3.0 |
| 1.20 < V ≤ 1.40 | 15.0 |

(3) Nothing in paragraph (2) above shall be interpreted to require a DC Tie to trip for voltage conditions beyond those for which ride-through is required.

(4) The owner of a DC Tie meeting the applicability requirements of paragraph (1) above shall ensure any protective over- or under-voltage relay for the DC Tie is set to enable the DC Tie to ride through any voltage condition beyond those defined in paragraph (2) above to the maximum extent possible within the DC Tie’s capability.

(5) A DC Tie shall not cease injecting electric current during any period in which ride-through is required pursuant to paragraph (2) and paragraph (4) above. A DC Tie shall return to the pre-disturbance level of real power transfer within 1 second of POIB voltage recovery to normal operating range.