(i) Management of Interconnection Reliability Operating Limits (IROLs) shall not change.

4.5.3 Implementation

(1) ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) representing Resources and Transmission Operators (TOs), and coordinating the implementation of the EEA conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each declared EEA level.

(2) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using Direct Current Tie(s) (DC Tie(s)) or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with North American Electric Reliability Corporation (NERC) scheduling guidelines.

(3) ERCOT, at management's discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

(4) There may be insufficient time to implement all levels in sequence. ERCOT may immediately implement EEA Level 2 when clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT may immediately implement Level 3 of the EEA any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz for any duration of time. ERCOT shall immediately implement Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(5) Percentages for Level 3 Load shedding will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs and TSPs. QSEs and TSPs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

[NOGRR177: Replace paragraph (6) above with the following upon system implementation of NPRR857:]

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs, TSPs, and DCTOs. QSEs, TSPs, and DCTOs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or

his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

(7) During EEA Level 3, ERCOT must be capable of manually shedding sufficient firm Load to arrest frequency decay and to prevent ~~generator~~ tripping of generators. The amount of manual firm Load to be shed may vary depending on ERCOT Transmission Grid conditions during the event. Each TSP will be capable of manually shedding its allocation of firm Load, without delay. The maximum time for the TSP to interrupt firm Load will depend on how much Load is to be shed and whether the Load is to be interrupted by Supervisory Control and Data Acquisition (SCADA) or other, non-SCADA-controlled methods. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. Each TO, TSP, and Transmission and/or Distribution Service Provider (TDSP) and their designated agents will comply with the following requirements when implementing an ERCOT instruction to shed firm Load:

(a) Load interrupted manually by SCADA will be shed without delay upon receipt of a Load shed instruction and in a time period not to exceed 30 minutes after receipt of the Load shed instruction for each Entity's portion of every Load shed instruction. SCADA-controlled Load shed is preferred to be utilized by the TO and/or TDSP(s) before non-SCADA-controlled Load shed when executing a Load shed instruction;

(b) If sufficient amounts of SCADA-controlled Load are not available to fulfill an Entity's manual Load shed instruction, the TO and/or TDSP(s) shall complete, if applicable, the remaining manual Load shed through non-SCADA-controlled Load shed methods without delay upon receipt of a Load shed instruction and in a time period not to exceed one hour after receipt of the Load shed instruction. A TO shall notify ERCOT if its SCADA-controlled Load shed capabilities have been exhausted; and

(c) If determined appropriate by the TO and as soon as practicable, the TO and/or TDSP(s) should restore SCADA-controlled Load by shedding non-SCADA-controlled Load not shed in paragraph (b) above, in an effort to make SCADA-controlled Load available for a potential subsequent Load shed instruction.

(8) Each TSP, or its designated agent, will provide ERCOT a status report of Load shed progress within 30 minutes of the time of ERCOT's instruction or upon ERCOT's request.

(9) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(a) of Section 4.5.3.1, General Procedures Prior to EEA Operations, ERCOT may control the post-contingency flow to within the 15-Minute Rating in Security-Constrained Economic Dispatch (SCED). After Physical Responsive Capability (PRC) is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

4.5.3.2 General Procedures During EEA Operations

(1) ERCOT Control Area authority will re-emphasize the following operational practices during EEA operations to minimize non-performance issues that may result from the pressures of the emergency situation.

(a) ERCOT shall suspend Ancillary Service obligations that it deems to be contrary to reliability needs;

(b) ERCOT shall notify each QSE representing Resources and TO via ERCOT QSE and TO Hotlines of each declared EEA level and shall post the declared EEA level electronically to the ERCOT website;

(c) QSEs and TOs shall notify each represented Market Participant of declared EEA level;

(d) ERCOT, QSEs and TSPs shall continue to respect confidential market sensitive data;

[NOGRR177: Replace paragraph (d) above with the following upon system implementation of NPRR857:]

(d) ERCOT, QSEs, TSPs, and DCTOs shall continue to respect confidential market sensitive data;

(e) QSEs shall update Current Operating Plans (COPs) to limit or remove capacity when unexpected start-up delays occur or when ramp limitations are encountered;

(f) QSEs shall report when On-Line or available capacity is at risk due to adverse circumstances;

(g) QSEs, TSPs, and all other Entities must not suspend efforts toward expeditious compliance with the applicable EEA level declared by ERCOT nor initiate any reversals of required actions without ERCOT authorization;

[NOGRR177: Replace paragraph (g) above with the following upon system implementation of NPRR857:]

(g) QSEs, TSPs, DCTOs, and all other Entities must not suspend efforts toward expeditious compliance with the applicable EEA level declared by ERCOT nor initiate any reversals of required actions without ERCOT authorization;

(h) ERCOT shall define procedures for determining the proper redistribution of reserves during EEA operations; and

(i) QSEs shall not remove an On-Line Generation Resource or Energy Storage Resource (ESR) without prior ERCOT authorization unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, QSEs shall immediately inform ERCOT of the need and reason for removing the On-Line ~~Generation~~ Resource from service.

5.1 System Modeling Information

(1) Information on existing and future ERCOT System components and topology is necessary for ERCOT to create databases and perform tests as outlined in these criteria. To ensure that such information is made available to ERCOT, the following actions by Market Participants are required:

(a) Each Transmission Service Provider (TSP), or its Designated Agent, shall provide accurate modeling information for all Transmission Facilities owned or planned by the TSP. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the TSP's Transmission Facilities in any model of the ERCOT Transmission Grid whose creation has been approved by ERCOT, including modeling information detailed in procedures of the Steady State Working Group (SSWG), Dynamics Working Group (DWG), and System Protection Working Group (SPWG);

(ii) Identification of a designated contact person, generally regarded as the working group TSP representative, responsible for providing answers to questions ERCOT may have regarding the information provided; and

(iii) TSP owned or operated Transmission Facility data provided and used to accurately represent a Transmission Facility in a model shall be consistent to the extent practicable with data provided and used to represent that same Transmission Facility in any other model created to represent a time period during which the Transmission Facility is expected to be physically identical. All existing transmission lines' and transformers' impedances, or equivalent branch circuit impedance, and Ratings shall be identical, to the extent practicable. If all normally closed breakers and switches are closed and normally open breakers and switches are open in the Network Operations Model, the calculated line flows between substations in the Annual Planning Model shall be consistent, when all models use the same load magnitude and distribution, generation~~ and energy storage~~ commitment and dispatch, and Voltage Profile.

(b) Each TSP, or its Designated Agent, owning or planning Transmission Facilities shall attend the scheduled meetings and otherwise participate in the activities of the SSWG, DWG, and the SPWG, unless specifically exempted from these activities by ERCOT.

(c) Each Generation Resource and Energy Storage Resource (ESR), or ~~its~~ a Designated Agent for the Resource, shall provide accurate modeling information for each existing or proposed ~~Generation~~ Resource meeting the criteria for inclusion in the SSWG, DWG, and SPWG base cases for which it is the majority owner. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the ~~Generation~~ Resource's generation and interconnection facilities in any model of the ERCOT System whose creation has been approved by ERCOT, including modeling information detailed in procedures of the SSWG, DWG, and SPWG; and

(ii) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided.

[NOGRR177: Replace paragraph (c) above with the following upon system implementation of NPRR857:]

(c) Each Generation Resource, Energy Storage Resource (ESR), or Direct Current Tie Operator (DCTO), or ~~its~~a Designated Agent for the Resource or DCTO, shall provide accurate modeling information for each existing or proposed ~~Generation~~ Resource or Transmission Facility meeting the criteria for inclusion in the SSWG, DWG, and SPWG base cases for which the ~~Generation~~ Resource or DCTO is the majority owner. The information provided shall include, but not be limited to, the following:

(i) Information necessary to represent the ~~Generation~~ Resource's generation and interconnection facilities and the DCTO's Transmission Facilities in any model of the ERCOT System whose creation has been approved by

ERCOT, including modeling information detailed in procedures of the SSWG, DWG, and SPWG; and

(ii) Identification of a designated contact person responsible for providing answers to questions ERCOT may have regarding the information provided.

(d) Typical or representative information may be provided for planned facility additions or modifications for use in the SSWG, DWG, and SPWG base cases, but such information shall be revised using actual design or construction information in accordance with the time line for Network Operations Model changes outlined in Protocol Section 3.10.1, Time Line for Network Operations Model Changes.

(e) Congestion Revenue Right (CRR) Network Model Outage determination uses network topology of the CRR Network Model identified by ERCOT. This must include Outages of Transmission Elements with a status of approved or accepted by ERCOT at the time the CRR Network Model is being built and that demonstrate significant impact to the transfer capability during the effective period. ERCOT will consider including Outages in the CRR Network Model that are scheduled to occur in the relevant time period and meet one or more of the following criteria:

(i) Consecutive or continuous approved or accepted Outages greater than or equal to five days;

(ii) Approved or accepted Outages which include Transmission Elements included in the definition of a Hub;

(iii) Approved or accepted Outages which include Transmission Elements in a 345 kV Transmission Facility;

(iv) Approved or accepted Outages that require the use of a Block Load Transfer (BLT); and

(v) Any other approved or accepted Outage that has been determined by ERCOT to carry a substantial risk of causing significant congestion.

(f) As set forth in Protocol Section 7.5.1, Nature and Timing, all Outages included in the CRR Network Model shall be posted on the Market Information System (MIS) Secure Area consistent with the model posting requirements and with accompanying cause and duration information, as indicated in the Outage Scheduler.

6.1.2.2 Fault Recording and Sequence of Events Recording Equipment Location

Requirements

(1) The location criteria listed below apply to Transmission Facilities operated at or above 100 kV unless otherwise specified. The Facility owner, whether a Transmission Facility owner, ~~or~~a Generation Resource owner, or an Energy Storage Resource (ESR) owner, shall, as applicable, install fault recording and sequence of events recording equipment at the following locations, at a minimum:

(a) Locations identified by the Transmission Facility owner utilizing the methodology in Section 8, Attachment M, Selecting Buses for Capturing Sequence of Events Recording and Fault Recording Data;

(b) Additional locations selected at the Transmission Facility owner's discretion, utilizing the methodology in Section 8, Attachment M;

(c) Locations operating at or above 60 kV, as defined below.

(i) Interconnections with Control Areas outside the ERCOT Region;

(ii) Substations where electrical transfers can be made between the ERCOT Control Area and a Control Area outside the ERCOT Region;

(iii) All switchyards owned by a Generation Resource or ESR connected to the ERCOT System with an aggregated gross generating ~~and energy storage~~ nameplate capacity above 100 MVA.

(d) For locations that have experienced an abnormal trip or immediate Load change greater than or equal to 20 MW (including if caused by a Distribution Generation Resource (DGR), Distribution Energy Storage Resource (DESR), or Settlement Only Distribution Generator (SODG)) after a fault:

(i) ERCOT may require the installation of fault recording and sequence of events recording equipment;

(ii) The interconnecting TSP or DSP shall ensure recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than 18 months after ERCOT notifies the TSP or DSP of the need to install the equipment, unless ERCOT provides an extension; and

(v) If the TSP or DSP determines that the recording equipment installation is infeasible due to engineering, technical or operational reasons, it will provide such rationale to ERCOT.

(e) For any Load consisting of one or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more Service Delivery Points:

(i) ERCOT may require the installation of fault recording and sequence of events recording equipment;

(ii) The interconnecting TSP or DSP shall ensure the recording equipment is installed;

(iii) A suitable location for the recording equipment will be coordinated between ERCOT and the interconnecting TSP or DSP;

(iv) The recording equipment will be installed as soon as practicable, but no longer than 18 months after ERCOT notifies the TSP or DSP of the need to install the equipment, unless ERCOT provides an extension; and

(v) If the TSP or DSP determines that the recording equipment installation is infeasible due to engineering, technical or operational reasons, it will provide such rationale in writing to ERCOT.

(2) Transmission Facility owners or Generation Facility owners shall install the applicable fault recording and sequence of events recording equipment identified in paragraph (1) above as soon as practicable.

[NOGRR255: Replace paragraph (2) above with the following no earlier than August 1, 2026:]

(2) Facility owners shall have at least 50% of the new fault recording and sequence of events recording equipment identified in paragraph (1) above installed.

[NOGRR255: Delete paragraph (2) no earlier than August 1, 2028 and renumber accordingly.]

(3) For any Generation Resource or ESR that has not installed fault recording or sequence of events recording equipment and experiences an unexpected trip or significant reduction in output in response to a system disturbance after a fault for which it is unable to determine the cause, ERCOT may require the installation of fault recording and sequence of events recording equipment consistent with the requirements of Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment. The Generation Resource or ESR owner shall install the fault recording and sequence of events recording equipment at an ERCOT-specified location as soon as practicable but no longer than 18 months after the date that ERCOT notifies the Facility owner it must install the equipment, unless the requestor provides an extension.

6.1.2.3 Fault Recording and Sequence of Events Recording Data Requirements

(1) Each Transmission Facility owner, ~~and~~ Generation Resource owner, and ESR owner shall have fault recording data to determine the following electrical quantities for each triggered fault recording for the locations specified in Section 6.1.2.2, Fault Recording and Sequence of Events Recording Equipment Location Requirements:

(a) Phase-to-neutral voltage for each phase of each specified bus with two sets of substation voltage measurements for breaker-and-a-half and ring bus substation configurations and one set of substation voltage measurements for each bus in other substation configurations;

(b) For transmission lines, each phase current and neutral (residual) current; and

(c) For transformers with a low-side operating voltage of 100kV or above, each phase current and the neutral (residual) current. These phase currents can be from either the high-side or low-side of the transformer.

(2) Each Transmission Facility owner, ~~and~~ Generation Resource owner, and ESR owner shall have sequence of events recording data per the following requirements:

(a) Circuit breaker position (open/close) for each circuit breaker it owns associated with the required monitored elements and connected directly to the transmission buses identified in paragraphs (1)(a) and (1)(b) of Section 6.1.2.2; and

(b) The following data as either part of the sequence of events recording data or fault recording digital status data:

(i) Circuit breaker position for each circuit breaker that it owns associated with monitored generator ~~or energy storage~~ interconnects, transmission lines, and transformers;

(ii) Carrier transmitter control status (i.e. start, stop, keying) for associated transmission lines; and

(iii) Carrier signal receive status for associated transmission lines.

(3) Each Generation Resource owner and ESR owner shall have the following fault recording data for each triggered fault recording to determine:

(a) Time stamp;

(b) Phase-to-neutral voltage for each phase on low or high side of the Main Power Transformer (MPT);

(c) Each phase current and the residual or neutral current on low or high side of the MPT;

(d) If applicable, active and reactive power on low or high side of the MPT;

(e) If applicable, frequency and rate-of-change-of-frequency (df/dt) data for at least one generator-interconnected bus measurement;

(f) If applicable, dynamic reactive device input/output such as voltage, current, and frequency; and

(g) Applicable binary status.

(4) If the fault recorder does not directly measure the values in paragraphs (3)(d) through (3)(f) above, then dynamic disturbance recording or phasor measurement unit data is acceptable so long as data of sufficient resolution is available to validate dynamic models, identify protection system actions, and identify the cause of a ride-through failure.

(5) For each requested Facility identified by ERCOT in paragraphs (1)(d) and (1)(e) in Section 6.1.2.2, the interconnecting TSP or DSP shall have the following fault recording and sequence of events recording data for the identified Load elements to determine:

(a) Phase-to-neutral voltage for each phase of the transmission bus serving the Load, or other ERCOT-approved voltages;

(b) Each phase current and neutral current for each Load terminal, or other ERCOT-approved currents; and

(c) Circuit breaker status for those transmission circuit breakers directly associated with the Load terminals.

6.1.2.4 Fault Recording and Sequence of Events Recording Data Retention and Reporting Requirements

(1) Each Transmission Facility owner~~ and~~ Generation Resource owner, and ESR owner shall, upon request, provide to ERCOT fault recording and sequence of events recording data for the Transmission Elements identified in these requirements as follows:

(a) Data shall be maintained and retrievable for at a minimum:

(i) Twenty calendar days, including the day the data was recorded, for fault recording and sequence of events recording equipment installed on or replaced after June 1, 2024;

(ii) Ten calendar days, including the day the data was recorded, for fault recording and sequence of events recording equipment installed prior to June 1, 2024;

(b) Data subject to paragraph (1)(a) above will be provided within seven calendar days of request unless the requestor grants an extension;

(c) Sequence of events recording data will be provided in ASCII Comma Separated Value (CSV) format as follows: Date, Time, Local Time Code, Substation, Device, State;

(d) Fault recording data that is not calculated will be provided in electronic files formatted in conformance with Institute of Electrical and Electronic Engineers (IEEE) C37.111, IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later;

(e) Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later; and

(f) If available, fault recording data may be provided in electronic files in SEL ASCII event report (.EVE), compressed ASCII (.CEV), or Motor Start Report (.MSR) in both raw and filtered format in addition to the data required above.

(2) The Transmission Facility owner, ~~and~~ Generation Resource owner, and ESR owner providing the requested fault recording and sequence of events recording data to ERCOT, the NERC Regional Entity, or NERC shall store the data for at least three years from the date the data was created.

6.1.3.1.2 Dynamic Disturbance Recording Equipment Location Requirements

(1) ERCOT shall identify and provide notification to Facility owners who shall install and maintain dynamic disturbance recording equipment at the following locations:

(a) A Generation Resource(s) that is not an IBR and ESR(s) with:

(i) Gross individual nameplate rating greater than or equal to 500 MVA; or

(ii) Gross individual nameplate rating greater than or equal to 300 MVA if the gross plant/facility aggregate nameplate rating is greater than or equal to 1,000 MVA;

(b) Any Transmission Element part of a stability-related (angular or voltage) system operating limit;

(c) Each terminal of a high-voltage, direct current (HVDC) circuit with a nameplate rating greater than or equal to 300 MVA, on the alternating current side of a converter;

(d) One or more Transmission Elements part of an Interconnection Reliability Operating Limit (IROL); and

(e) Any one Transmission Element within a major voltage sensitive area as defined by an area with an in-service UVLS program.

(2) ERCOT shall identify, and notify Facility owners of, a minimum dynamic disturbance recording coverage, including Transmission Elements identified above, of a least:

(a) One Transmission Element; and

(b) One Transmission Element per 3,000 MW of ERCOT's historical simultaneous peak Demand.

6.1.3.1.3 Dynamic Disturbance Recording Data Recording and Redundancy Requirements

(1) Recorded electrical quantities shall determine the following:

(a) For Transmission Facilities meeting the requirements in Section 6.1.3.1.2, Dynamic Disturbance Recording Equipment Location Requirements:

(i) Phase-to-neutral voltage magnitude/angle data for each phase from at least two distinct transmission level element measurement points;

(ii) Single phase current magnitude/angle data for each phase from at least two distinct transmission lines; and

(iii) Frequency and rate-of-change-of-frequency (df/dt) data for at least two Transmission Element measurement points.

(b) For Generation Resource owner and ESR owner locations meeting the requirements in Section 6.1.3.1.2:

(i) Phase-to-neutral voltage, or phase-to-phase voltage magnitude/angle data for each phase from at least one generator- ~~or Energy Storage System (ESS)-~~interconnected bus measurement point;

(ii) Single phase current magnitude/angle data for each phase from each interconnected generator on the high or low side of a MPT;

(iii) Active and reactive power on low or high side of the MPT;

(iv) Frequency and df/dt data for at least one generator- ~~or ESS-~~interconnected bus measurement; and

(v) If applicable, dynamic reactive device input/output such as voltage, current, and frequency.

6.1.3.1.4 Dynamic Disturbance Recording Data Retention and Data Reporting Requirements

(1) A Market Participant required to have and maintain data regarding electrical quantities shall maintain and retain that data, at a minimum:

(a) A rolling ten calendar day period for all data;

(b) At least three years for event data used for model validation in accordance with NERC Reliability Standards; and

(c) At least three years for event data provided to ERCOT, the NERC Regional Entity, or NERC via written request recorded in the context of an event analysis or review.

(2) Each affected Market Participant shall provide to ERCOT, upon request, dynamic disturbance recording data as follows:

(a) Data must be retrievable for ten calendar days, including the day the data was recorded;

(b) Data subject to paragraph (2)(a) above within seven calendar days of a request unless the requestor grants an extension;

(c) Dynamic disturbance recording data in electronic files formatted in conformance with IEEE C37.111, revision C37.111-1999 or later;

(d) Data files named in conformance with IEEE C37.232, revision C37.232-2011 or later.

6.1.5 Maintenance and Testing Requirements

(1) Each Market Participant with dynamic disturbance recording, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Fault Recording and Sequence of Events Recording Equipment, Section 6.1.3, Dynamic Disturbance Recording Equipment Including Phasor Measurement Unit Equipment, and Section 6.1.4, Fault Recording, Sequence of Events Recording, and Phasor Measurement Unit Requirements for Inverter-Based Resources (IBRs), shall maintain and test its equipment as follows:

(a) Calibrate or configure the devices at installation and when records from the equipment indicate a calibration or configuration problem;

(b) To ensure data stored locally is available upon request by verifying data availability and quality at least once every 60 calendar days, or institute an automated notification system to detect when the equipment ceases recording required data or fails to timely refresh the data.

(2) Each Market Participant with dynamic disturbance recording equipment, phasor measurement recording, fault recording, or sequence of events recording equipment identified by Section 6.1.2, Section 6.1.3, and Section 6.1.4 shall, within 90 calendar days of discovering a failure of the required data production, either:

(a) Restore the recording capability, or

(b) Notify and submit to ERCOT a plan and timeline for restoring the equipment recording capabilities.

6.2.3 Performance Analysis Requirements for ERCOT System Facilities

(1) All ERCOT System disturbances (unwanted trips, faults, and protective relay system operations) shall be analyzed by the affected facility owner(s) promptly and any deficiencies shall be investigated and corrected.

(2) All protective relay system misoperations and all associated corrective actions in Generation Resource systems, Energy Storage Resource (ESR) systems, or Transmission Facility systems 100 kV and above shall be documented, and documentation shall be supplied by the affected Facility owner(s) to ERCOT per the timeline established in paragraph (6) below or upon request. Any of the following events constitute a reportable protective relay system misoperation:

(a) Failure to Trip – Any failure of a protective relay system to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device (zone of protection includes both the reach and time characteristics). Lack of targeting, such as when a high-speed pilot system is beat out of high-speed zone is not a reportable misoperation. Furthermore, if the fault clearing is consistent with the time normally expected with proper functioning of at least one protection system, then a primary or backup protection system failure to operate is not required to be reported;

(b) Slow Trip – An operation of a protective relay system for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intent;

(c) Unnecessary Trip During a Fault – Any unnecessary protective relay system operation for a fault not within the zone of protection. Operation as backup protection for a fault in an adjacent zone that is not cleared within the specified time for the protection for that adjacent zone is not a reportable operation; and

(d) Unnecessary Trip Other Than Fault – Any unnecessary protective relay system operation when no fault or other abnormal condition has occurred. Note that an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable misoperation.

(3) Any of the following events do not constitute a reportable protective relay system misoperation:

(a) Trip Initiated by a Control System – Operations which are initiated by control systems (not by protective relay system), such as those associated with generator ~~or Energy Storage System (ESS)~~ controls, or turbine/boiler controls, Static Var Compensators, Flexible AC Transmission devices, HVDC terminal equipment, circuit breaker mechanism, or other facility control systems, are not considered protective relay system misoperations;

(b) Facility owner authorized personnel action that directly initiates a trip is not considered a misoperation. It is the intent of this reporting process to identify misoperations of the protective relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the protective relay system. If an individual directly initiates an operation, it is not counted as a misoperation (i.e., unintentional operation during tests); however, if a technician leaves trip test switches or cut-off switches in an inappropriate position and a system fault or condition causes a misoperation, this would be counted as a protective relay system misoperation; and

(c) Failure of Relay Communications – A communication failure in and of itself is not a misoperation if it does not result in misoperation of the associated protective relay system.

(4) All Remedial Action Scheme (RAS) misoperations shall be documented, including corrective actions, and the documentation supplied to ERCOT, the Reliability Monitor, and the NERC Regional Entity, per the timeline established in paragraph (1) of Section 11.2.1, Reporting of RAS Operations. Any of the following events constitute a reportable RAS misoperation:

(a) Failure to Operate – Any failure of a RAS to perform its intended function within the designed time when power system conditions intended to trigger the RAS occur;

(b) Unnecessary Operation – Any operation of a RAS that occurs without the occurrence of the intended system trigger condition(s);

(c) Unintended System Response – A RAS operates for the system conditions it was designed to operate for but the RAS operation results in an unintended adverse power system response;

(d) Failure to Mitigate – A RAS operates for the system conditions it was designed to operate for but fails to mitigate the power system conditions it was designed to address;

(e) Failure to Arm – Any failure of a RAS to automatically arm itself when power system conditions that are intended to arm the RAS occur; and

(f) Failure to Disarm or Reset – Any failure of a RAS to automatically disarm or reset itself when power system conditions that are intended to disarm the RAS occur.

(5) Transmission Facility owners shall document the performance of their protective relay systems. The performance data reported shall include the total number of protective relay system misoperations and the total number of events.

(6) Protective relay system misoperations shall be reported to ERCOT using either the Relay Misoperations Report form on the ERCOT website or any other form that contains the same information and that is provided in a similar format as the ERCOT Relay Misoperations Report. Relay Misoperation Reports shall be submitted to ERCOT at shiftsupv@ercot.com on a quarterly basis per the following schedule:

Data submission	**Date***
Submission of the 1st Quarter data	May 31
Submission of the 2nd Quarter data	August 31
Submission of the 3rd Quarter data	November 30
Submission of 4th Quarter data	February 28
**Next Business Day if date specified is a non-Business Day*	

(7) All Facility owners shall install, maintain, and operate disturbance monitoring equipment in accordance with the requirements in Section 6.1.2.3, Fault Recording and Sequence of Events Recording Data.

6.2.6.1.1 Dependability

(1) Except as noted in paragraphs (4) and (5) below, all elements of the ERCOT System operated at 100 kV and above (i.e., lines, buses, transformers, generators, ~~ESSs,~~ breakers, capacitor banks, etc.) shall be protected by two protective relay systems. Each protective relay system shall be independently capable of detecting and isolating all faults thereon.

(2) The protective relay system design should avoid the use of components common to the two protective relay systems. Areas of common exposure should be kept to a minimum to reduce the possibility of both protective relay systems being disabled by a single contingency.

(3) The use of two identical protective relay systems is not generally recommended, due to the risk of simultaneous failure of both protective relay systems because of design deficiencies or equipment problems.

(4) Breaker failure protection should be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This protection need not be duplicated.

(5) On installations where freestanding or column-type current transformers are provided on one side of the breaker only, the protective relay systems should be provided to detect a fault on the primaries of such current transformers. This protection need not be duplicated. Application of freestanding current transformers requires extra care to ensure that the relaying is proper and that the schemes overlap.

6.2.6.1.6 Analysis of System Performance and Associated Protection Systems

(1) Relay operation and settings shall be reviewed periodically and whenever significant changes in generating ~~or energy storage~~ sources, transmission facilities, or operating conditions are anticipated.

(2) Naturally occurring faults and other system disturbances should be analyzed as a source of information as to the health of relay schemes in the facility owner's system and the ERCOT System. Sources of information usually available are:

(a) Short circuit study for the exact conditions of the fault;

(b) Fault recorder traces;

(c) Sequence of events data recording the opening and closing of contacts in the protective relay scheme and associated communication equipment;

(d) Fault locator data;

(e) SCADA logger output of breaker operation and alarms;

(f) Interviews with operating personnel and/or other witnesses;

(g) Field report of relay flags and breaker counter changes;

(h) Field report of the fault location, if found;

(i) Records of relay setting, relay testing, trip check and energize procedures as carried out, in-service measurements, relay wiring diagrams and schematics, manufacturers' information;

(j) Other utility personnel and System Protection Working Group (SPWG) members; and

(k) Manufacturers' application and design engineers.

(3) Steps that may be followed in analyzing a disturbance include:

(a) Gather data;

(b) Create a time line consisting of events and periods between events;

(c) Compare actual and calculated values of current and voltage during the periods between events;

(d) Compare actual and expected breaker operations and flags;

(e) Choose the least complicated explanation for contradictory information and to fill in missing information;

(f) Gather additional information as indicated to prove or disprove explanations;

(g) Iterate;

(h) Document by issuing a report of all findings, changes, and recommendations; and

(i) After a reasonable time, check back to see if the recommendations have been carried out.

6.2.6.3.6 Automatic Under-Voltage Load Shedding Protection Systems

(1) Automatic Under-Voltage Load Shedding (UVLS) systems are classified as protective relay systems. The maintenance requirements, discussed in Section 6.2.5, Maintenance and Testing Requirements for ERCOT System Facilities, apply to UVLS protection systems as well.

(2) The requirement for under-voltage relaying shall be determined by system studies performed/administered by ERCOT designated working groups or equipment owners. The system studies should indicate the following:

(a) Amount of Load to be shed to restore voltage to minimum acceptable level or higher;

(b) The minimum and maximum time delay allowed before automatically shedding Load;

(c) The voltage level(s) at which to initiate automatic relay operation; and

(d) The location(s) for effectively applying UVLS protection systems.

(3) Automatic UVLS protection systems need not be duplicated.

(4) Analyses shall be performed on UVLS schemes by working groups and/or equipment owners as assigned by ERCOT to demonstrate that they are expected to act before generators~~ or ESSs~~ trip Off-Line due to the protective relay requirements, as specified in paragraph (4)(a) of Section 2.9, Voltage Ride-Through Requirements for Generation Resources and Energy Storage Resources. A specific exemption from this analysis requirement may be provided by the ROS.

(5) Under-voltage protection systems shall be designed to coordinate with other protective devices and control schemes during momentary voltage dips, sustained faults, low voltages caused by stalled motors, motor starting, etc.

(6) Automatic Load restoration for an UVLS operation is not currently utilized in ERCOT.

(7) The UVLS scheme shall be designed to ensure reliable operation. The scheme shall not impede continued operation of any Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) during a UVLS event, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs).

(8) In addition, protective relaying for Generation Resources and ESRs must be designed to meet Voltage Ride-Through (VRT) criteria as detailed in Section 2.9.

(9) Restoration of any Load shed by UVLS shall be coordinated with ERCOT.

9.1.2 Compliance with Valid Dispatch Instructions

(1) ERCOT shall produce monthly reports detailing Resource-specific Regulation Service and energy deployment performance, including Load Resources, based on the criteria described in Protocol Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance and Ancillary Service Capacity Performance Metrics.

(2) ERCOT shall produce a report for any system-wide deployment of Load Resources on an event basis, within 90 days after the event occurs and shall post it to the MIS Secure Area.

9.3.2 System and Resource Control

(1) The following reports shall be posted on the MIS Secure Area:

[NOGRR266: Replace paragraph (1) above with the following upon system implementation of NPRR1239:]

(1) The following reports shall be posted on the ERCOT website:

(a) Resource control metrics:

(i) Total Regulation Up Service (Reg-Up) and Regulation Down Service (Reg-Down) per interval - ERCOT shall develop a monthly report detailing the total amount of Reg-Up energy deployed in the Settlement Interval and by hour and the total amount of Reg-Down energy deployed for each Settlement Interval and by hour of the Operating Day.

(b) Reliability Unit Commitments (RUCs) and deployments:

(i) For each month, ERCOT shall report, Generation Resources committed in each RUC process, the reason for the commitment, Resource name and intervals deployed, and the hours committed for Voltage Support Service (VSS).

(c) Reversal of Base Point instructions to Generation Resources and Energy Storage Resources (ESRs) from interval to interval:

(i) ERCOT shall record and report, on a monthly basis, instances of Dispatch Instructions to Resources not providing Regulation Service in which there is a directional change in Base Point instructions for four consecutive Security-Constrained Economic Dispatch (SCED) intervals for validation and review.

11.2 Remedial Action Schemes

(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools.

[NOGRR215: Replace paragraph (1) above with the following upon system implementation:]

(1) Remedial Action Schemes (RASs) are designed to detect abnormal predetermined ERCOT System conditions and automatically take corrective actions to maintain a secure system. Any RAS proposed on or after June 24, 2020 may not be approved or implemented unless ERCOT has first determined that the RAS is necessary to avoid an actual or anticipated violation of transmission security criteria, as defined in Section 2.2.2, Security Criteria, that cannot be resolved through ERCOT market tools, or unless the RAS would allow a Generation Resource of the type described in paragraph (3) of Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, to operate at a level that comports with the minimum deliverability criteria in Planning Guide Section 4.1.1.7.

(2) The following do not individually constitute a RAS:

(a) Protection systems installed for the purpose of detecting faults on Transmission Elements and isolating the faulted Transmission Elements;

(b) Schemes for automatic Under-Frequency Load Shedding (UFLS) and automatic Under-Voltage Load Shedding (UVLS) comprised of only distributed relays;

(c) Out-of-step tripping and power swing blocking;

(d) Automatic reclosing schemes;

(e) Schemes applied on a Transmission Element for non-fault condition, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage or overload to protect the Transmission Element against damage by removing it from service;

(f) Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and that are located at and monitor quantities solely at the same station as the Transmission Element being switched or regulated;

(g) FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device;

(h) Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched;

(i) Schemes that automatically de-energize a line for a non-faults operation when one end of the line is open;

(j) Schemes that provide anti-islanding protection (e.g., protect Load from effects of being isolated with generation ~~or energy storage~~ that may not be capable of maintaining acceptable frequency and voltage);

(k) Automatic sequences that proceed when manually initiated solely by a System Operator;

(l) Modulation of high voltage, direct current (HVDC) or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillation;

(m) Sub-synchronous resonance protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations); or

(n) Generation controls such as, but not limited to, Automatic Generation Control (AGC), generation excitation (e.g., Automatic Voltage Regulator (AVR) and Power System Stabilizers (PSSs)), fast valving, and speed governing.

(3) In addition to the requirements in the Protocols and applicable North American Electric Reliability Corporation (NERC) Reliability Standards, RASs shall also meet the following requirements:

(a) A RAS may be proposed by a Transmission Service Provider (TSP) or Resource Entity, and be approved by ERCOT and the TSP(s) and/or Resource Entity(ies) included in the RAS prior to implementation;

(b) The design, implementation, and testing of the RAS shall be coordinated within the RAS Entity;

(c) The RAS shall be automatically armed when appropriate;

(d) The RAS shall not operate unnecessarily;

(e) A RAS designated as a Limited Impact RAS shall be reviewed according to the process described in paragraph (4)(e) below and subject to ERCOT approval;

(f) For a RAS not designated by ERCOT as a Limited Impact RAS, the possible inadvertent operation of the RAS, resulting from any single RAS component malfunction satisfies all of the following as determined by the review process in paragraph (4)(e) below and subject to ERCOT approval:

(i) The ERCOT System shall remain stable;

(ii) Cascading shall not occur;

(iii) Applicable Facility Ratings shall not be exceeded;

(iv) ERCOT System voltages shall be within post-contingency voltage limits and post-contingency voltage deviation limits;

(v) Transient voltage responses shall be within acceptable limits.

(g) To avoid unnecessary RAS operation, the RAS Entity may provide a Real-Time status indication to the owner of any Generation Resource or Energy Storage Resource (ESR) controlled by the RAS to show when the flow on one or more of the RAS monitored Facilities exceeds 90% of the flow necessary to arm the RAS. The cost necessary to provide such status indication shall be the responsibility of the RAS Entity;

(h) The status indication of any automatic or manual arming/activation or operation of the RAS shall be provided as Supervisory Control and Data Acquisition (SCADA) alarm inputs to the owner(s) of any Facility controlled by the RAS;

(i) When a RAS is removed from service, the RAS Entity or a Designated Agent shall immediately notify ERCOT;

(j) When a RAS is returned to service, the RAS Entity or its Designated Agent shall immediately notify ERCOT. ERCOT shall modify its reliability constraints to recognize the availability of the RAS;

(k) The RAS Entity shall telemeter the status indication of the following items by SCADA to ERCOT for incorporation into ERCOT systems:

(i) Any automatic or manual arming/activation or operation of the RAS;

(ii) The in-service/out-of-service status of the RAS; and

(iii) Any additional related telemetry that already exists pertinent to the monitoring of the RAS (e.g. status indication of communications links between associated RAS equipment and the owner's control center, arming limits of associated RAS equipment); and

(l) The TSP may receive telemetry for a Resource Entity owned RAS through ERCOT or through the RAS Entity, at the option of the TSP. The RAS Entity, at its own cost, must provide telemetry for Resource Entity owned RASs to the TSP upon request.

(4) The RAS Entity shall submit to ERCOT documentation of an existing, modified, proposed, or retiring RAS for review and compilation into an ERCOT RAS database using the form in Section 8, Attachment K, Remedial Action Scheme (RAS) Template. The documentation shall detail the design, operation, modeling, functional testing, and coordination of the RAS with other RASs, Automatic Mitigation Plans (AMPs), protection and control systems. The exit strategy described in the RAS submission shall identify the ERCOT endorsed transmission project or near-term mitigation that will address the constraint.

(a) ERCOT shall conduct a review of each proposed new or modified RAS and each proposed retirement of a RAS. Within five Business Days of receipt, ERCOT shall post the proposal to the Market Information System (MIS) Secure Area and shall issue a Market Notice describing the proposal and inviting submission of Market Participant comments. Within 30 Business Days of receiving the proposal, ERCOT shall complete an evaluation of the proposal in accordance with paragraph (4)(e) below and shall issue a Market Notice approving or rejecting the proposal. ERCOT shall coordinate any additional time needed for the evaluation with the RAS Entity. Additionally, ERCOT shall conduct a review of each existing RAS at least once every three years or as required by changes in system conditions.

(b) The review of a proposed RAS shall be completed before the RAS is placed in service. The timing of placing the RAS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Network Operations Model Change Request (NOMCR) to ERCOT.

(c) Existing RASs that have already undergone at least one review shall remain in service during any subsequent review. Modifications to existing RASs may be implemented upon approval by ERCOT.

(d) The schedule for placing a RAS into service must be coordinated among ERCOT and the RAS Entity, and shall provide sufficient time to perform any necessary functional testing prior to its being placed in service.

(e) For any proposed, modified, or existing RAS, ERCOT's review of the RAS shall:

(i) Validate that RAS is needed to mitigate the system condition(s) or contingency(ies) for which it was designed, and that the RAS actions, designed timing, and arming conditions mitigate those system condition(s) or contingency(ies);

(ii) Identify any conflicts with the Protocols, NERC Reliability Standards, and this Operating Guide;

(iii) Validate that transient voltage responses are within acceptable limits as established by ERCOT;

(iv) Evaluate and document the consequences of misoperation, incorrect operation, unintended operation, or failure of a RAS. Additionally, validate that the RAS is designed to meet the requirements in paragraphs (3)(e) and (3)(f) above;

(v) Validate that the proposed RAS facilitates periodic testing and maintenance;

(vi) Determine whether or not the RAS is a Limited Impact RAS;

(vii) Validate that the proposed RAS avoids adverse interactions with other RASs, AMPs, protection and control systems, and applicable emergency procedures;

(viii) Evaluate the effects of future bulk electric system modifications on the design and operation of the RAS where applicable;

(ix) Validate the implementation of RAS logic appropriately correlates desired actions (outputs) with events and conditions (inputs);

(x) Validate the mechanism of procedure by which the RAS is armed is clearly described, and is appropriate for reliable arming and operation of the RAS for the conditions and events for which it is designated to operate; and

(xi) Evaluate future transmission project(s) that will eliminate the need for the RAS.

(f) Upon completion of ERCOT's RAS review, ERCOT shall provide all results and underlying studies to the RAS Entity and each impacted TSP.

(g) If deficiencies are identified for a new, functionally modified, or retiring RAS by ERCOT or other parties' comments, the RAS Entity shall either submit an amended RAS proposal or withdraw the RAS proposal. The amended RAS proposal shall undergo the review process specified in paragraph (4)(e) above using the 30 Business Day RAS review timeline in paragraph (4)(a) above until the identified deficiencies have been resolved to the satisfaction of ERCOT.

(h) For any proposed retirement of a RAS, ERCOT shall evaluate whether the proposed retirement will cause any reliability concern, including whether the proposed retirement will adversely impact the dispatch of a Generation Resource or ESR subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria. After considering any comments submitted, if ERCOT does not identify any reliability concern, ERCOT shall issue a Market Notice indicating its approval of the proposed retirement of the RAS. If ERCOT does identify a reliability concern or an adverse impact to the dispatch of a Generation Resource or ESR subject to the minimum deliverability criteria set forth in Planning Guide Section 4.1.1.7, ERCOT shall issue a Market Notice denying the retirement.

(i) As part of the ERCOT review, ERCOT may notify the Steady State Working Group (SSWG), the Dynamics Working Group (DWG), and the System Protection Working Group (SPWG) of the RAS proposal, and each working group or any member of each working group may provide any comments, questions, or issues to ERCOT. ERCOT may work with the owner(s) of Facilities affected by the RAS as necessary to address all issues.

(j) ERCOT shall develop a method to include the RAS where practicable in Security-Constrained Economic Dispatch (SCED), Outage coordination, and Reliability Unit Commitment (RUC).

(k) ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the RAS.

(l) ERCOT shall update the RAS database at least once every 12 calendar months.

(5) ERCOT shall provide the results of the RAS evaluation including any identified deficiencies to the RAS Entity and impacted TSPs. If ERCOT's RAS evaluation identifies a deficiency within six calendar months, the RAS Entity shall develop and submit a corrective action plan, subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed.

(6) If ERCOT determines that a RAS is no longer needed, either as part of an ERCOT-initiated review or as a consequence of ERCOT's determination that a transmission project has addressed the condition(s) or contingency(ies) the RAS was designed to address, ERCOT shall issue a Market Notice proposing to retire the RAS and inviting comments from Market Participants on the proposed retirement. After considering all comments, if ERCOT confirms that the RAS is not needed, then ERCOT shall retire the RAS on a date specified in a separate Market Notice.

(7) The RAS Entity shall perform a functional test of each of its RAS to verify the overall RAS performance and the proper operation of non-protection system components at least once every six calendar years for a RAS not designated as a Limited Impact RAS, and

once every 12 calendar years for a RAS designated as a Limited Impact RAS. For any identified deficiencies, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, to correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed.

11.2.1 Reporting of RAS Operations

(1) RAS Entity shall notify ERCOT of all RAS operations. Documentation of RAS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report form as an email to ras_cmp@ercot.com. Within 120 calendar days, the RAS Entity shall conduct an analysis of all RAS operations, misoperations, and failures. If deficiencies are identified, the RAS Entity shall develop and submit a corrective action plan within six calendar months, and subject to ERCOT approval, correct the deficiencies. For each plan developed, the RAS Entity shall implement the approved plan, update the plan if actions or timetables change, and notify ERCOT via email at ras_cmp@ercot.com if plan actions or timetables change and when the plan is completed. Analysis of RAS operational performance shall include, but is not limited to:

(a) Determination of whether system events or conditions appropriately armed or triggered the RAS;

(b) Determination of whether the RAS responded as designed;

(c) Determination of whether the RAS was effective in mitigating the performance issues it was designed to address; and

(d) Determination of whether the RAS operation resulted in any unintended or adverse system response.

(2) ERCOT shall report all RAS operations and misoperations to the Reliability Monitor for review. RAS arming or activation that ramps generation~~ or energy storage~~ back is not considered an operation or misoperation with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity. A misoperation of a RAS with respect to reporting requirements to the Reliability Monitor and the NERC Regional Entity occurs when one of the items specified in paragraph (4) of Section 6.2.3, Performance Analysis Requirements for ERCOT System Facilities, occur. RAS Entities will provide a monthly report to ERCOT by the 15th of each month describing each instance a RAS armed/activated and reset during the previous month. The report will include the date and time of arming/activation and reset. ERCOT shall consolidate the monthly reports and forward to the Reliability Monitor and NERC Regional Entity on a quarterly basis.

(3) If a RAS which removes generation~~ or energy storage~~ from service operates more than two times within a six month period and the operations are not a direct result of an ERCOT System disturbance or a contingency operation, ERCOT may require the

Resource Entity(ies) representing the Generation Resource or ESR~~Entity(ies)~~ to decrease the available capability on the affected ~~Generation~~ Resource(s). The amount of available capacity to be decreased shall be determined by ERCOT. The decreased available capacity on the ~~Generation~~ Resource(s) shall remain until the ~~Generation~~ Resource Entity(ies) provides documentation that demonstrates the ~~Generation~~ Resource(s) can properly control output in a pre-contingency or normal ERCOT System condition.

ERCOT Impact Analysis Report

NOGRR Number	268	NOGRR Title	Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
Impact Analysis Date	July 31, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1246, Energy Storage Resource Terminology Alignment for the Single-Model Era.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1246.

Board Report

NOGRR Number	**271**	**NOGRR Title**	**Related to NPRR1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response**
Date Posted	February 4, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	2.3.1.2.1, Limit on Generation Resources and Controllable Load Resources Providing RRS Section 8 Attachment N, Procedure for Calculating RRS Limits for Individual Resources		
Related Documents Requiring Revision/Related Revision Requests	NPRR1257 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) is related to NPRR1257 and specifies how the maximum limit on the amount of Responsive Reserve (RRS) that an individual Resource can provide using Primary Frequency Response will be used in Section 8, Attachment N. This NOGRR also proposes some clean-up to the Section 8, Attachment N language.		
Reason for Revision	☒ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice		

	by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	ERCOT determined that instituting a maximum limit on the amount of RRS that an individual Resource can provide using Primary Frequency Response is necessary based on GE Vernova's recommendation contained in its report presented to ERCOT stakeholders at the RRS-PFR Limits Study Workshop on April 6, 2023.
ROS Decision	On 11/7/24, ROS voted unanimously to table NOGRR271 and refer the issue to the Performance, Disturbance, Compliance Working Group (PDCWG). All Market Segments participated in the vote. On 12/5/24, ROS voted unanimously to recommend approval of NOGRR271 as submitted. All Market Segments participated in the vote. On 1/9/25, ROS voted unanimously to endorse and forward to TAC the 12/5/24 ROS Report and 10/21/24 Impact Analysis for NOGRR271. All Market Segments participated in the vote.
Summary of ROS Discussion	On 11/7/24, ERCOT Staff provided an overview of NOGRR271 and confirmed the proposed limit would be imposed at a Resource level rather than a site level. Participants requested additional review by PDCWG. On 12/5/24, participants noted the PDCWG discussions addressed their original questions with NPRR1257 and NOGRR271. On 1/9/25, there was no discussion.
TAC Decision	On 1/22/25, TAC voted unanimously to recommend approval of NOGRR271 as recommended by ROS in the 1/9/25 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/22/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification

Board Report

	[X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 2/4/25, the ERCOT Board voted unanimously to recommend approval of NOGRR271 as recommended by TAC in the 1/22/25 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR271.
ERCOT Opinion	ERCOT supports approval of NOGRR271.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR271 and believes the market impact for NOGRR271, along with NPRR1257, applies a reasonable limit on the amount of RRS from Primary Frequency Response that is provided by an individual Resource to address the risk of common mode failure, in line with recommendations from GE Vernova.

Sponsor	
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Company	ERCOT
Phone Number	512-248-6601 / 512-248-4577
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Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

2.3.1.2.1 Limit on ~~Generation~~ Resources ~~and Controllable Load Resources~~ Providing RRS Using Primary Frequency Response

(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) and actual tests.

(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 MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response, 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.

ERCOT Nodal Operating Guides
Section 8
Attachment N

Procedure for Calculating RRS MW Limits for Individual Resources to Provide RRS Using Primary Frequency Response

~~May 1, 2024~~TBD

Board Report

1. Introduction

Changes to this attachment shall be reviewed by the Performance, Disturbance, Compliance Working Group (PDCWG).

2. Responsive Reserve Service Using Primary Frequency Response

Responsive Reserve (RRS) using Primary Frequency Response is an operating reserve on Generation Resources, Controllable Load Resources, and Energy Storage Resources (ESRs)~~, and Resources capable of providing Fast Frequency Response (FFR)~~ maintained by ERCOT to help control the frequency of the system. RRS on ~~Generation~~ Resources ~~and Controllable Load Resources that are capable of~~ providing Primary Frequency Response can be released to Security-Constrained Economic Dispatch (SCED) during scarcity conditions as outlined in Section 4.8, Responsive Reserve Service During Scarcity Conditions.

3. RRS MW LIMITS FOR INDIVIDUAL RESOURCES

~~Thermal~~Generation Resources, ESRs, and Controllable Load Resources that do not meet the 12 months or the last eight Frequency Measurable Events (FMEs) (applicable if a minimum threshold of eight FMEs within the 12 month period is not met) rolling average criteria, or have failed to score greater than or equal to 0.75 for Primary Frequency Response initial or Primary Frequency Response sustained measures (computed per Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response) for three consecutive FMEs, where the unit was evaluated, over a minimum period of two calendar months, will be subject to review of their respective RRS MW limit for Primary Frequency Response (PFR) ("RRS MW Limit") using the process outlined in Section 4 below. All other ~~thermal~~Generation Resources, ESRs, and Controllable Load Resources shall continue to be limited to ~~20% of~~ their respective RRS MW Limit established as follows~~High Sustained Limit (HSL) as their RRS limit~~.

1. The default RRS MW ~~l~~Limit for any ~~new thermal~~ Generation Resource, ESR, or Controllable Load Resource providing RRS shall be set to ~~the lower of~~ 20% of its HSL ~~or Maximum Power Consumption (MPC), as appropriate~~. A Private Use Network with a registered Resource may use its gross HSL for qualifying and establishing a limit on the amount of RRS capacity that the Resources within the Private Use Network can provide.

2. RRS MW ~~l~~Limits for non-thermal Generation Resources, ~~or~~ Generation Resources with a Resource Category of either (i) aeroderivative simple cycle commissioned after 1996, or (ii) Reciprocating Engines, ESRs, or Controllable Load Resources may be updated to be higher or lower than the default~~20%~~ threshold based on their droop performance characteristics~~,~~ and actual tests~~, and the need to keep the frequency responsive capability fairly distributed across multiple Resources~~.

3. In order to ensure that the frequency responsive capability is distributed across multiple Resources, the RRS MW Limit for all Generation Resources, ESRs, or Controllable Load Resources may be further adjusted based on the maximum amount of RRS that an individual Resource can provide using PFR established per paragraph (3) of Protocol Section 3.16, Standards for Determining Ancillary Service Quantities.

Based on Protocol Section 3.18, Resource Limits in Providing Ancillary Service, (i) Generation Resources operating in synchronous condenser fast-response mode may provide RRS up to the Generation Resource's ERCOT-validated 20-second response capability (which may be 100% of their HSL)~~, and (ii) Resources providing RRS as FFR may provide RRS up to the Resource's ERCOT-validated 15-minute capability~~.

4. CALCULATING RRS MW LIMITS FOR INDIVIDUAL RESOURCES

For Resources that fail the Primary Frequency Response initial or Primary Frequency Response sustained measures for three consecutive FMEs, where the unit was evaluated, over a minimum period of two calendar months or are failing the 12 months or the last eight FMEs (applicable if a minimum threshold of eight FMEs within the 12 month period is not met) rolling average criteria, ERCOT shall establish RRS MW L~~l~~imit for providing RRS using PFR based on their respective performance during FMEs, any limitations exhibited within its dynamic models, or through droop performance tests on an as needed basis.

If the RRS MW L~~l~~imit is to be determined based upon the Resource's performance during an FME, then such RRS MW L~~l~~imit shall be calculated as follows,

1. The RRS MW Limit for each Generation Resource, ESR, and Controllable Load Resource will be calculated using the droop performance during an FME. The Calculated Droop Performance and RRS MW Limit for an FME is calculated as follows:

$$Calculated\ Droop\ Performance\ (Droop) = \frac{(HSL - PA\ Capacity) * (\Delta Hz - Deadband_{max})}{ScheduledFrequency * \Delta MW}$$

$$Calculated\ RRS\ MW\ Limit\ (\%) = \frac{0.01 * ScheduledFrequency - Deadband_{max}}{ScheduledFrequency * Droop} * 100$$

Delta Hertz (ΔHz): The pre-perturbation [the 16-second period of time before t(0)] average frequency minus the post-perturbation [the 32-second period of time starting 20 seconds after t(0)] average frequency

Delta MW (ΔMW): The pre-perturbation average MW of the Resource minus the post-perturbation average MW of the Resource

Scheduled Frequency: The frequency value to be maintained on the system, always 60 Hz

Power Augmentation (PA) Capacity: The telemetered portion of a Generation Resource's HSL that represents the sustainable non-Dispatched power augmentation capability from duct firing, inlet air cooling, auxiliary boilers, or other methods which does not immediately respond, arrest, or stabilize frequency excursions during the first minutes following a disturbance without secondary frequency response or instructions from ERCOT

Deadband (Deadband$_{max}$): The range of deviations of system frequency (+/-) that produces no PFR

2. The median of the calculated RRS MW Limits in the last five FMEs where the unit was evaluated will be computed for each individual Generation Resource, ESR, and Controllable Load Resource. If a Resource hasn't participated in five FMEs, proceed to Step 3.

3. The median of all FMEs during the previous three months where the unit was evaluated will be computed for each individual Generation Resource, ESR, and Controllable Load Resource.

4. RRS MW Llimit will be established based on the lower of the values computed in Steps 2 and 3.

If a Generation Resource's, ESR's, or Controllable Load Resource's performance during an FME is excluded per the current process (NERC Reliability Standard BAL-TRE-001) from the rolling average calculation, the Resource's performance will also be excluded from the RRS MW Limit calculation. Also note that all members of a Combined Cycle Generation Resource will be evaluated as one Generation Resource for the purposes of this evaluation.

5. TIMELINE TO ESTABLISH RRS MW LIMITS

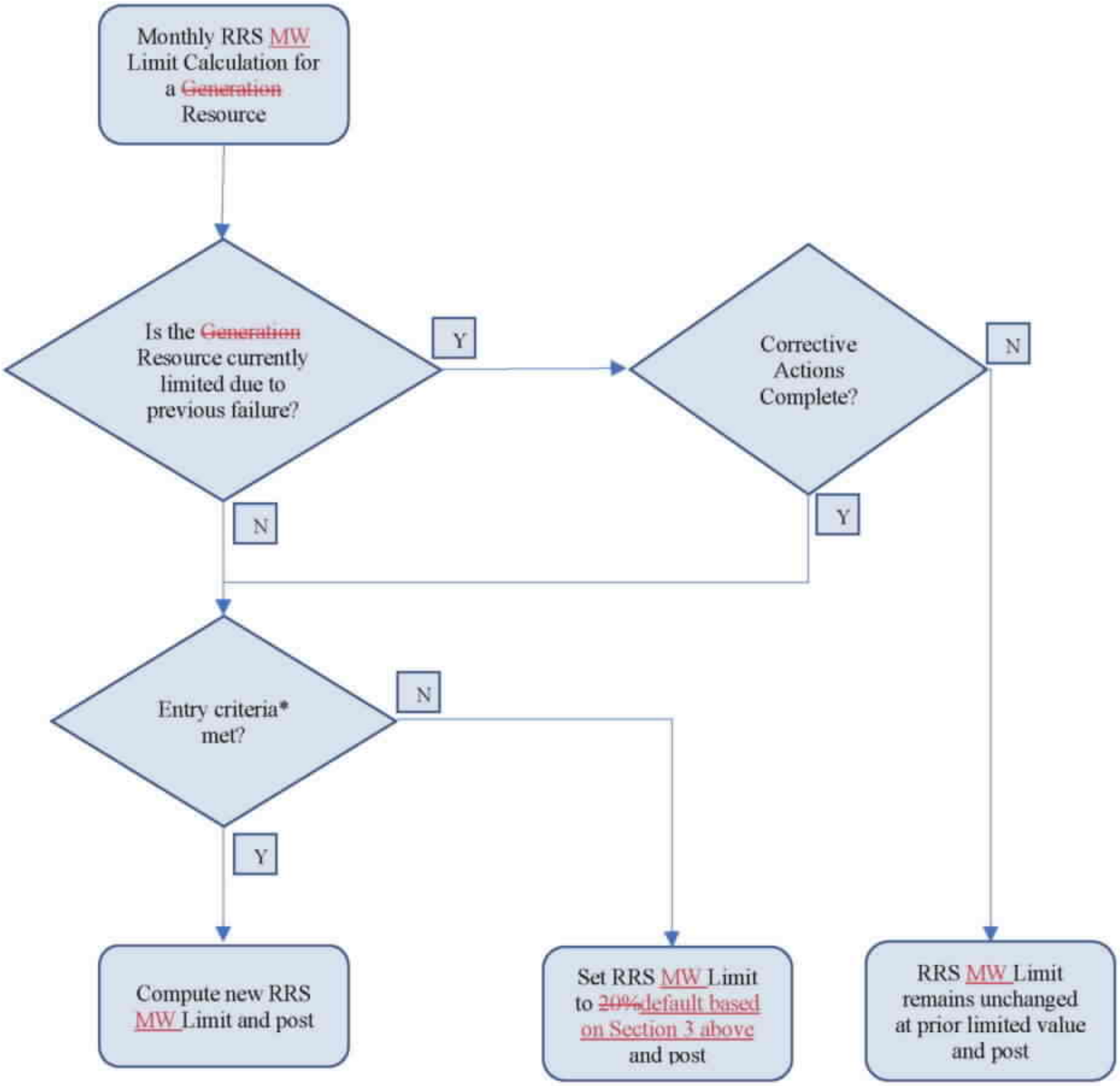
ERCOT will recalculate the RRS MW Limit on each individual Generation Resource, ESR, and Controllable Load Resource on a monthly basis. ERCOT shall post on the Market Information System (MIS) Certified area the RRS MW Llimit for each Resource qualified to provide RRS by the 10th day of each month. These RRS MW Llimits will be effective in ERCOT systems coincident with the first Network Model Database Load[1] two months later. For example, ERCOT shall post the RRS MW Limit for each Resource by January 10, 2020. These RRS MW Limits will be effective in ERCOT systems beginning March 4, 2020. These recalculated values will follow any threshold limitations as expressed in Section 3 above.

If at the time of recalculation, a Generation Resource, ESR, or Controllable Load Resource was previously limited due to any failure mentioned in Section 4 above, then the established RRS MW Llimit will continue to apply. In order to reset the RRS MW Llimit, a Generation Resource, ESR, or Controllable Load Resource may use dynamic models, droop performance tests, or documentation of an implemented corrective action plan to demonstrate that it is capable of carrying the standard RRS limit as mentioned in Section 3 above. A Generation Resource, ESR, or Controllable Load Resource that requests its RRS MW Limit to be reset must have a current 12 months or the last eight FMEs rolling average of at least 0.75 for Primary Frequency Response initial or sustained measures.

[1] The most recent Network Model Database Load Schedules can be accessed at the following link. **https://www.ercot.com/gridinfo/transmission/opsys-change-schedule**

APPENDIX: RRS MW LIMIT DECISION TREE

The diagram below describes at a high level the decision tree ~~this~~ procedure ~~will~~to compute a RRS MW L~~l~~imit for every Generation Resource, ESR, and Controllable Load Resource. In the event there is a conflict between the diagram below and text stated in the sections above, the language stated in text above takes precedence.



*(1) failed rolling average or (2) score in last three evaluated events in two consecutive months is less than~~<~~ 0.75

ERCOT Impact Analysis Report

NOGRR Number	271	NOGRR Title	Related to NPRR1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response
Impact Analysis Date	October 21, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1257.

Board Report

OBDRR Number	052	OBDRR Title	Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
Date of Decision		February 4, 2025	
Action		Recommend Approval	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		Upon implementation of Nodal Protocol Revision Request (NPRR) 1246, Energy Storage Resource Terminology Alignment for the Single-Model Era	
Priority and Rank Assigned		Not applicable	
Other Binding Document Requiring Revision		Procedure for Identifying Resource Nodes	
Related Documents Requiring Revision/Related Revision Requests		Nodal Operating Guide Revision Request (NOGRR) 268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era NPRR1246 Planning Guide Revision Request (PGRR) 118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era	
Revision Description		This Other Binding Document Revision Request (OBDRR) inserts terminology associated with Energy Storage Resources (ESRs) in the appropriate places throughout the Procedure for Identifying Resource Nodes, aligning provisions and requirements for ESRs with those already in place for Generation Resources and Controllable Load Resources. While several key sections of this OBD have already been modified to accommodate ESRs in the "combo model" era — in which ESRs are treated as two Resources — numerous other provisions and requirements rely on the blanket provision from NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions, in paragraph (1) of Protocol Section 3.8.5, Energy Storage Resources, as follows:	

	"For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise." As discussed at meetings in 2020 of the Battery Energy Storage Task Force (BESTF), ERCOT intended for this provision to be temporary, and explained to stakeholders that it would introduce an NPRR and related Revision Requests in 2021 that incorporated the ESR terminology in all appropriate locations in the Nodal Protocols. This OBDRR accomplishes that objective in the Procedure for Identifying Resource Nodes. This OBDRR is applicable to ESRs in the future single-model era and should be implemented simultaneously with NPRR1246 and NPRR1014, BESTF-4 Energy Storage Resource Single Model. ERCOT invites review of this OBDRR from the Real-Time Co-Optimization plus Batteries Task Force (RTCBTF) and any other applicable groups. It is also worth noting these changes have no system impacts as they reflect the current RTC+B business requirements and interface requirements for Market Participants.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This OBDRR improves transparency and ease of access to provisions and requirements for ESR developers and Market Participants.

TAC Decision	On 8/28/24, TAC voted unanimously to table OBDRR052. All Market Segments participated in the vote. On 11/20/24, TAC voted unanimously to recommend approval of OBDRR052 as amended by the 10/14/24 ERCOT comments; and the 7/31/24 Impact Analysis. All Market Segments participated in the vote. On 1/22/25, TAC voted unanimously to recommend approval of OBDRR052 as recommended by TAC in the 11/20/24 TAC Report as amended by the 1/21/25 ERCOT comments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/28/24, participants noted the related Revision Requests were still under consideration by the relevant subcommittees and requested tabling of OBDRR052. On 11/20/24, there was no additional discussion beyond TAC review of the items below. On 1/22/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed [ ] Other: (explain)
ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to remand OBDRR052 to TAC. On 2/4/25, the ERCOT Board voted unanimously to recommend approval of OBDRR052 as recommended by TAC in the 1/22/25 TAC Report.

Opinions	
Credit Review	Not applicable

Board Report

Independent Market Monitor Opinion	IMM has no opinion on OBDRR052.
ERCOT Opinion	ERCOT supports approval of OBDRR052.
ERCOT Market Impact Statement	ERCOT Staff has reviewed OBDRR52 and believes the market impact for OBDRR052 provides clarity and additional transparency for stakeholders on the applicable provisions and requirements associated with ESRs as the market transitions from the combo model to the single model as part of the RTC+B project.

Sponsor	
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Company	ERCOT
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Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
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Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**
ROS 091024	Requested TAC continue to table OBDRR052
ERCOT 101424	Proposed additional edits to align with similar comments to NPRR1246 removing/rephrasing initially proposed uses of “ESR”
ERCOT 012125	Proposed additional edits to align with OBDRR046, Related to NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources

Market Rules Notes

Board Report

Please note that the baseline language below has been updated to reflect the incorporation of the following OBDRR(s) into this OBD:

- OBDRR046 (incorporated 12/1/24)

Proposed Other Binding Document Language Revision

Introduction:

This procedure is the guiding document for ERCOT and Market Participants with a Generation Resource~~s~~ or Energy Storage Resource (ESR)~~,~~ to identify Resource Nodes and manage the lifecycle of the Resource Node.

> ***[OBDRR046: Replace the paragraph above with the following upon system implementation of NPRR1188:]***
>
> This procedure is the guiding document for ERCOT and Market Participants with a Generation Resource~~s~~, Energy Storage Resource (ESR), or Controllable Load Resource~~s~~ (CLR~~s~~) that is~~are~~ not an Aggregate Load Resource~~s~~ (ALR~~s~~), to identify Resource Nodes and manage the lifecycle of the Resource Node.

Revisions to this document must be approved by the Technical Advisory Committee (TAC). In the following cases, after review and recommendation by TAC, revisions to this document must be approved by the ERCOT Board:

a. The revisions require an ERCOT project for implementation; and

b. The revisions are related to a Nodal Protocol Revision Request (NPRR), a Planning Guide Revision Request (PGRR), or a revision request requiring an ERCOT project for implementation.

Upon approval of revisions, ERCOT shall post the revised procedure to the ERCOT website within three Business Days.

Procedure to Incorporate a Resource Node into the Network Operations Model:

1. At the designated time period as determined by Protocol Section 3.10, Network Operations Modeling and Telemetry, and associated ERCOT business processes, a Resource Entity must submit Resource Registration information that includes a detailed electrical one-line drawing of the generation facility. The ERCOT business process indicates that the Resource Registration information will be presented to the Network Modeling Group within ERCOT.
2. The Network Modeling Group will utilize the "Principles for Resource Node Definition" located in Appendix A to determine the Resource Node parameters.
3. The Network Modeling Group will provide documentation back to the Resource Entity clearly indicating the Resource Node parameters.
4. The Resource Entity will have five Business Days to accept or reject the suggested Resource Node parameters.
5. If there are any disagreements with the Resource Node parameters, ERCOT and the Resource Entity shall work together to reach agreement.

6. If agreement cannot be reached by ERCOT and the Resource Entity, the Wholesale Market Subcommittee (WMS) or appropriate WMS working group shall help guide the decision.

7. Upon an agreement between ERCOT and the Resource Entity, the Resource Node parameters will be implemented in the Network Operations Model.

8. The normal timeline for this procedure shall not exceed 20 Business Days after the submission date of validated Resource Registration information that includes a detailed electrical one-line drawing.

9. In the event that agreement between ERCOT and the Resource Entity cannot be reached within 20 Business Days, no Resource Node parameters will be entered into the Network Operations Model. This may have an effect on Congestion Revenue Right (CRR) Network Models and associated CRR activities regarding the Generation Resource or ESR in question. There must be an agreement between ERCOT and the Resource Entity before Resource Node parameters will be implemented into the Network Operations Model.

[OBDRR046: Replace paragraph 9 above with the following upon system implementation of NPRR1188:]

9. In the event that agreement between ERCOT and the Resource Entity cannot be reached within 20 Business Days, no Resource Node parameters will be entered into the Network Operations Model. This may have an effect on Congestion Revenue Right (CRR) Network Models and associated CRR activities regarding the Generation Resource, ESR or CLR in question. There must be an agreement between ERCOT and the Resource Entity before Resource Node parameters will be implemented into the Network Operations Model.

10. Once effective in the Network Operations Model, the Resource Node name cannot be changed.

11. Once incorporated into the Network Operations Model, the Resource Node will be used in all associated ERCOT models, applications, and processes.

12. The Resource Node parameters, associated electrical one-line drawings, and other relevant data shall be posted on the Market Information System (MIS) Secure Area and will be available to Market Participants with Digital Certificates.

Procedure to Retire a Resource Node in the Network Operations Model:

1. Resource Nodes cannot be retired until all outstanding CRRs on that Resource Node have been settled or a model error was identified in the creation of the Resource Node. Transmission Service Providers (TSPs) cannot submit Network Operations Model Change Requests (NOMCRs) to delete a Resource Node.

2. ERCOT's ~~CRR~~ Forward Markets team will identify a nearby energized bus to move the location of the retiring Resource Node until such time as all the outstanding CRRs are settled once it has been notified that equipment tied to a Resource Node is requested to be removed from the Network Operations Model. In this specific case, the Resource Node location will not follow the rules in this document and it may not be located near a Generation Resource or ESR.

[OBDRR046: Replace paragraph 2 above with the following upon system implementation of NPRR1188:]

2. ERCOT's Forward Markets team will identify a nearby energized bus to move the location of the retiring Resource Node to until such time as all the outstanding CRRs are settled once it has been

notified that equipment tied to a Resource Node is requested to be removed from the Network Operations Model. In this specific case, the Resource Node location will not follow the rules in this document, and it may not be located near a Generation Resource, ESR, or CLR.

3. ERCOT's CRR team will submit a NOMCR with the appropriate effective date to remove the retiring Resource Node in the future. The effective date is determined based on the last active CRR date.

4. ERCOT's Day-Ahead Market (DAM) team will update the Resource Node expiration date in the Market Management System (MMS) based on the retirement of the Resource Node.

Appendix A

PRINCIPLES FOR RESOURCE NODE DEFINITION

1. Network Operations Model

a. Annual/Monthly CRR Auctions use a network model as close as possible to the Network Operations Model.

b. MMS and Energy Management System (EMS) use the same Network Operations Model for both commercial and operational purposes.

c. Breakers between the Resource Connectivity Nodes and the Resource Node are assumed closed by default so that Resource Nodes and associated Resource Connectivity Nodes appear energized.

d. Transmission Element Outages, as defined in the Protocols, are submitted into the Outage Scheduler and posted before DAM submission, i.e. de-energized Resource Nodes (Settlement Points) are known in advance of DAM submission.

2. Resource Connectivity Nodes

a. Resource Connectivity Node represents the Electrical Bus where physical generator~~ or ESR~~ is connected.

[OBDRR046: Replace paragraph a. above with the following upon system implementation of NPRR1188:]

a. Resource Connectivity Node represents the Electrical Bus where the physical generator is connected or the Electrical Bus of a Common Information Model (CIM) Load that a CLR is mapped to.

b. Generator output is injected and ~~input~~ESR charging consumption is withdrawn at the Resource Connectivity Node.~~ ESR output or input is injected or withdrawn at the Resource Connectivity Node, respectively.~~

[OBDRR046: Replace paragraph b. above with the following upon system implementation of NPRR1188:]

b. Generator output is injected and ESR charging consumption is withdrawn at the Resource Connectivity Node and CLR consumption is withdrawn at the Resource Connectivity Node.

c. More than one Resource can be connected to the same Resource Connectivity Node.

3. Resource Nodes

3.1 Resource Node Definition

a. Resource Node represents the Electrical Bus or the logical construct that defines the location of a Settlement Point.

b. Resource Nodes include Generation~~/Energy Storage~~ Resource Nodes, Combined Cycle Plant (CCP) Logical Resource Nodes, Combined Cycle Unit (CCU) Resource Nodes and Private Use Network (PUN) Resource Nodes.

c. A Generation~~/Energy Storage~~ Resource Node represents the Settlement Point for ERCOT and PUN Generation Resources and ESRs. The Three-Part Supply Offers, ~~including~~ Energy Bid/Offer Curves, DAM Energy-Only Offers, Ancillary Service Offers, and DAM Energy Bids, as well as Point-to-Point (PTP) bids, can be submitted and settled at a Generation~~/Energy Storage~~ Resource Node, unless that Generation~~/Energy Storage~~ Resource Node is within a PUN site where constrainable Transmission Element(s) exist between the Generation~~/Energy Storage~~ Resource Node and ERCOT-Polled Settlement (EPS) Meter, in which case only Three-Part Supply Offers, ~~including~~ Energy Bid/Offer Curves, and Ancillary Service Offers can be submitted and settled.

   i. Generation~~/Energy Storage~~ Resource Node within a PUN site refers to those Resource Nodes defined for Generation Resources and ESRs within a PUN site that cannot be placed at the PUN Point of Interconnection (POI) due to the rules for placement of Resource Nodes described in Section 3.2, Resource Node Location.

d. CCP Logical Resource Node represents the Settlement Point for Three-Part Supply Offers for CCP configurations. Only Three-Part Supply Offers, and Ancillary Service Offers for CCP configurations can be submitted and settled at a CCP Logical Resource Node.

e. CCU Resource Node represents the Settlement Point for the CCU. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted and settled at a CCU Resource Node.

f. PUN Resource Node represents the Settlement Point at the PUN interconnection to ERCOT. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted and settled at a PUN Resource Node.

g. Multiple Generation Resources and ~~multiple~~ ESRs can be mapped to the same Resource Node, i.e. offers from different Generation Resources and ESRs can be settled at the same Settlement Point.

h. A Generation Resource can only be mapped to one Resource Node, i.e. offers from ~~the~~a Generation Resource~~s~~ can only be settled at one Settlement Price. Similarly, an ESR can only be mapped to one Resource Node, i.e. offers/bids from an ESR can only be settled at one Settlement Price.

i. The Resource Nodes for "single" Resources and for Resources that are a component of a CCP shall be identified prior to the identification of the PUN Resource Nodes. Once those Resource Nodes have been located, the PUN Resource Nodes shall be located for PUN Resources that are not co-located with an existing Resource Node.

j. Resource Nodes shall not be located at the Direct Current Ties (DC Ties). (The DC Ties are Load Zones.)

k. Resource Nodes shall not be located at the Block Load Transfer (BLT) buses.

l. Do not identify or locate Resource Nodes for Non-Modeled Generators.

m. The Resource Node for a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) may be located at its Resource Connectivity Node.

[OBDRR046: Replace Section 3.1 above with the following upon system implementation of NPRR1188:]

3.1 Resource Node Definition

a. Resource Node represents the Electrical Bus or the logical construct that defines the location of a Settlement Point.

b. Resource Nodes include Generation/CLR Resource Nodes, Combined Cycle Plant (CCP) Logical Resource Nodes, Combined Cycle Unit (CCU) Resource Nodes and Private Use Network (PUN) Resource Nodes. ~~Note that for an ESR, the Resource Node for both the Generation Resource component as well as the CLR component is the same and the location of this single Resource Node for both components of the ESR is based on the guidelines described in this document for the placement of Resource Nodes for a Generation Resource~~.

c. Generation/CLR Resource Nodes represent the Settlement Points for ERCOT and PUN Generation Resources, ESRs and CLRs. The Three-Part Supply Offers, Energy Bid/Offer Curves Energy Bid Curves, DAM Energy-Only Offers, Ancillary Service Offers and DAM Energy Bids as well as Point-to-Point (PTP) bids can be submitted and settled at a Generation/CLR Resource Node, unless that Generation/CLR Resource Node is within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and ERCOT-Polled Settlement (EPS) Meter, in which case only Three-Part Supply Offers, Energy Bid/Offer Curves, Energy Bid Curves, and Ancillary Service Offers can be submitted and settled.

   i. Generation/CLR Resource Nodes within a PUN site refer to those Resource Nodes defined for Generation Resources, ESRs, and/or CLRs within a PUN site that cannot be placed at the PUN Point of Interconnection (POI) due to the rules for placement of Resource Nodes described in Section 3.2, Resource Node Location.

d. CCP Logical Resource Nodes represent the Settlement Points for Three-Part Supply Offers for CCP configurations. Only Three-Part Supply Offers and Ancillary Service Offers for CCP configurations can be submitted to be settled at a CCP Logical Resource Node.

e. CCU Resource Nodes represent the Settlement Points for the CCU. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted and settled at a CCU Resource Node.

f. PUN Resource Nodes represent the Settlement Points at the PUN interconnection to ERCOT. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted and settled at a PUN Resource Node.

g. Multiple Generation Resources, ESRs, and CLRs can be mapped to the same Resource Node, i.e. offers and/or bids from different Generation Resources, ESRs, and~~/or bids from~~ CLRs can be settled at the same Settlement Point.

h. A Generation Resource can only be mapped to one Resource Node, i.e. DAM offers from a Generation Resource can only be settled using one Settlement Point Price (SPP). Similarly, an ESR can only be mapped to one Resource Node, i.e. offers/bids from an ESR can only be settled using one SPP. A CLR can only be mapped to one Resource Node, i.e. DAM bids from a CLR can only be settled using one SPP.

i. The Resource Nodes for "single" Resources and for Resources that are a component of a CCP shall be identified prior to the identification of the PUN Resource Nodes. Once those Resource Nodes have been located, the PUN Resource Nodes shall be located for PUN Resources that are not co-located with an existing Resource Node.

j. Resource Nodes shall not be located at the Direct Current Ties (DC Ties). (The DC Ties are Load Zones.)

k. Resource Nodes shall not be located at the Block Load Transfer (BLT) buses.

l. Do not identify or locate Resource Nodes for Settlement Only Resources.

m. The Resource Node for a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) may be located at its Resource Connectivity Node.

3.2 Resource Node Location

a. First Fork Rule: Locate Resource Node at the first Electrical Bus with alternate paths starting from the Generation~~/Energy Storage~~ Resource Connectivity Node. Parallel network paths do not count as alternate paths.

  i. Exception: There is an exception to this rule for placing Generation~~/Energy Storage~~ Resource Nodes and CCU Resource Nodes that are mapped to Generation~~/Energy Storage~~ Resources or ESRs within a PUN. If the Generation Resource(s) and/or ESR(s) is within a PUN that has only one interconnection to the ERCOT Transmission Grid, locate the Resource Node at the Electrical Bus that is the interconnection point of the PUN to the ERCOT Transmission Grid.

  ii. ERCOT-Polled Settlement (EPS) Meter location check: As the network connectivity path is traversed in searching for the first Electrical Bus with alternate paths (First Fork Rule), if an Electrical Bus is encountered with a mapped EPS Meter first, then place the Resource Node at this Electrical Bus.

b. EPS Meter Rule: Locate Resource Node, subject to First Fork Rule, electrically as close as possible to EPS Meter location, i.e. where energy is effectively metered. If the EPS Meter location changes, then a new Resource Node must be established and the old Resource Node retired in accordance with the procedure in this document. Please refer to paragraph (h)(ii) below for a list of exceptions under which ERCOT can relocate a Resource Node.

c. Ownership Rule: Locate Resource Node at the Electrical Bus that is the ERCOT POI (if practical). Subsequent ownership changes shall not change the Resource Node location.

d. De-Energization Rule: Locate Resource Node at Electrical Bus that is less often de-energized, if alternate choices exist. Settlement Point Prices (SPPs) for de-energized Resource Nodes are calculated using heuristic rules.

e. Generic Transmission Constraint (GTC) Rule: A GTC cannot include Transmission Elements between a Resource Node and any Generation Resources or ESRs mapped to it.

f. Transmission Constraint Rule: Initial placement of the Resource Node should not be such that Transmission Elements between Resource Node and associated Resource Connectivity Nodes could be constrained. The parameters of the Network Operations Model are evaluated at that point in time when the determination of the Resource Node placement is being made such that there is no congestion between the location of the Resource Node and the Resource Connectivity Node that the Generation Resource or ESR is physically connected to in the Network Operations Model. Ongoing monitoring to ensure that there is no congestion between the Resource Node and the Resource Connectivity Node of the Generation Resource or ESR requires the Resource Entity and Transmission and/or Distribution Service Provider (TDSP) to monitor and coordinate changes that may impact this. See Articles 5, 6 and 7 of the Standard Generation Interconnection Agreement (SGIA).

g. Publicity Rule: Market Participants need to know where the Resource Nodes are located.

h. In the event of a subsequent NOMCR that changes the topology, ERCOT shall review the impact to the Resource Node location.

   i. In cases where a NOMCR, that is to be effective in the future, requires the placement of a new Resource Node, there may be instances where the Common Information Model (CIM) may show both the current and the future topology with the new Resource Node. This is done to handle situations where the energization date/time of the future network changes are different than the date/time of the migration of the changes in the network model into the ERCOT production systems. In such cases:

      A. The location of the new Resource Node will be based on the future topology only.

      B. The transition of the mapping between Generation~~/Energy Storage~~ Resource or ESR and the new Resource Node (if applicable) will be performed by ERCOT support staff.

   ii. ERCOT may relocate the existing Resource Node to an appropriate location to~~.~~:

      A. Align with the correct implementation of ~~NPRR1016, Clarify Requirements for Distribution Generation Resources (~~DGRs~~)~~ and ~~Distribution Energy Storage Resources (~~DESRs~~)~~, as stated in paragraph (m) of Section 3.1 above, in the Network Operations Model;

      B. Account for a series compensator(s); or

C. Implement station renames.

i. If all rules cannot be simultaneously satisfied, then the rules are listed in order of priority. ERCOT will use discretion in choosing the appropriate Resource Node location, assuming that such a location does not allow the Resource Entity to control its Resource Node price.

[OBDRR046: Replace Section 3.2 above with the following upon system implementation of NPRR1188:]

3.2 Resource Node Location

a. First Fork Rule: Locate Resource Node at the first Electrical Bus with alternate paths starting from the Generation Resource Connectivity Node for Generation Resources and ESRs and the Connectivity Node of the CIM Load that a CLR is mapped to for CLRs. Parallel network paths do not count as alternate paths.

i. Exception: There is an exception to this rule for placing Generation/CLR Resource Nodes and CCU Resource Nodes that are mapped to Generation Resources, ESRs, or ~~/~~CLRs within a PUN. If the Generation Resource(s) and/or ESR(s) and/or ~~/~~CLR(s) is within a PUN that has only one interconnection to the ERCOT Transmission Grid, locate the Resource Node at the Electrical Bus that is the interconnection point of the PUN to the ERCOT Transmission Grid.

ii. ERCOT-Polled Settlement (EPS) Meter Location Check: As the network connectivity path is traversed in searching for the first Electrical Bus with alternate paths (First Fork Rule), if an Electrical Bus is encountered with a mapped EPS Meter first, then place the Resource Node at this Electrical Bus. ~~The Resource Node for an ESR is the same for both the Generation Resource and CLR components of the ESR. The placement of the Resource Node for the components of an ESR is governed by the guidelines in this document for a Generation Resource.~~

b. EPS Meter Rule: Locate Resource Node, subject to First Fork Rule, electrically as close as possible to EPS Meter location, i.e. where energy is effectively metered. If the EPS Meter location changes, then a new Resource Node must be established and the old Resource Node retired in accordance with the procedure in this document. Please refer to paragraph (h)(ii) below for a list of exceptions under which ERCOT can relocate a Resource Node.

c. Ownership Rule: Locate Resource Node at the Electrical Bus that is the ERCOT POI (if practical). Subsequent ownership changes shall not change the Resource Node location.

d. De-Energization Rule: Locate Resource Node at Electrical Bus that is less often de-energized, if alternate choices exist. SPPs for de-energized Resource Nodes are calculated using heuristic rules.

e. Generic Transmission Constraint (GTC) Rule: A GTC cannot include Transmission Elements between a Resource Node and any Generation Resources, ESRs, or CLRs mapped to it.

f. Transmission Constraint Rule: Initial placement of the Resource Node should not be such that Transmission Elements between Resource Node and associated Resource Connectivity Nodes could be constrained. The parameters of the Network Operations Model are evaluated at that point in time when the determination of the Resource Node placement is being made such that there is no congestion between the location of the

Resource Node and the Resource Connectivity Node that the Generation Resource or ESR is physically connected to, or the Connectivity Node of the CIM Load that the CLR is mapped to, in the Network Operations Model. Ongoing monitoring to ensure that there is no congestion between the Resource Node and the Resource Connectivity Node of the Generation Resource or ESR, or the Connectivity Node of the CIM Load that the CLR is mapped to, requires the Resource Entity and Transmission and/or Distribution Service Provider (TDSP) to monitor and coordinate changes that may impact this. See Articles 5, 6 and 7 of the Standard Generation Interconnection Agreement (SGIA).

g. Publicity Rule: Market Participants need to know where the Resource Nodes are located.

h. In the event of a subsequent NOMCR that changes the topology, ERCOT shall review the impact to the Resource Node location.

   i. In cases where a NOMCR, that is to be effective in the future, requires the placement of a new Resource Node, there may be instances where the Common Information Model (CIM) may show both the current and the future topology with the new Resource Node. This is done to handle situations where the energization date/time of the future network changes are different than the date/time of the migration of the changes in the network model into the ERCOT production systems. In such cases:

      A. The location of the new Resource Node will be based on the future topology only.

      B. The transition of the mapping between the Generation Resource, ESR, or CLR and the new Resource Node (if applicable) will be performed by ERCOT support staff.

   ii. ERCOT may relocate the existing Resource Node to an appropriate location to:

      A. Align with the correct implementation of ~~NPRR1016, Clarify Requirements for Distribution Generation Resources (~~DGRs~~)~~ and ~~Distribution Energy Storage Resources (~~DESRs~~)~~, as stated in paragraph (m) of Section 3.1 above, in the Network Operations Model;

      B. Account for a series compensator(s); or

      C. Implement station renames.

i. If all rules cannot be simultaneously satisfied, then the rules are listed in order of priority. ERCOT will use discretion in choosing the appropriate Resource Node location, assuming such a location does not allow the Resource Entity to control its Resource Node price.

4. Combined Cycle Plant (CCP) Modeling

4.1 CCP Logical Resource Node

a. Each CCP configuration for a train represents a CCP Logical Generation Resource.

b. Each CCP Logical Generation Resource is mapped to a CCP Logical Resource Node. All CCP Logical Generation Resources, i.e. all CCP configurations for a train are mapped to the same CCP Logical Resource Node.

c. Each CCP train has its own CCP Logical Resource Node, i.e. CCP Logical Generation Resources for different CCP trains are mapped to different CCP Logical Resource Nodes.

d. Each CCP Logical Resource Node is a Settlement Point.

e. CCP Logical Resource Nodes are used only for Resource-specific Three-Part Supply Offers and Ancillary Service Offers for CCP configurations.

4.2 CCU Resource Node

a. CCU Resource Nodes are mapped to a CCP Logical Resource Node.

b. A CCU Resource Node is the Electrical Bus determined by above rules (First Fork and others as described in Section 3.2, Resource Node Location, above) starting from the Resource Connectivity Node of the physical CCP train Resources.

c. A CCU Resource Node is a Settlement Point.

d. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted at CCU Resource Nodes.

4.3 CCP/CCU Resource Node Processing

a. PTP cleared quantities are injected at Electrical Buses of CCU Resource Nodes.

b. DAM SPP for CCU Resource Node is used as Settlement Price for PTP bids that sink or source at CCU Resource Node.

c. In DAM, energy for CCP Logical Resource is distributed to Connectivity Nodes of physical CCP Resources proportionally to the Resource capacities that are On-Line in the selected CCP configuration.

d. In DAM, Shift Factor for CCP Logical Resource Node Dispatch is calculated as the High Reasonability Limit (HRL) weighted average of Shift Factors for CCU Resource Connectivity Nodes using the Resource HRLs that are On-Line in the selected CCP configuration as weights. Note that the assumption here is that there is no congestion between the connectivity node of the CCU and the Resource Node.

e. DAM SPP for CCP Logical Resource Node is equal to weighted average of DAM SPPs at CCU Resource Nodes using the Resource HRLs that are On-Line in selected CCP configuration as weights. For an Off-Line CCP, the LMP for the CCP Logical Resource Node is calculated as weighted average of LMPs at CCU Resource Nodes using the HRLs of the CCU Resources. Note that the assumption here is that there is no congestion between the Resource Connectivity Node of the CCU and the Resource Node.

f. DAM SPP for CCP Logical Resource Node is used as the Settlement Price for CCP Three-Part Supply Offers.

g. In Real-Time Market (RTM), Shift Factor for CCP Logical Resource Node is calculated as weighted average of Shift Factors for CCU Resource Connectivity Nodes using the telemetered outputs of CCU Resources that are online in current CCP configuration as weights. Note that the assumption here is that there is no congestion between the Resource Connectivity Node of the CCU and the Resource Node.

h. RTM Locational Marginal Price (LMP) for CCP Logical Resource Node when the CCP is On-Line is calculated based on the weighted average of Shift Factors at CCU Resource Connectivity Nodes using telemetered outputs of CCU Resources that are online in current CCP configuration as weights. For an Off-Line CCP, the LMP for the CCP Logical Resource

Node is calculated as weighted average of LMPs at CCU Resource Nodes using the HRLs of the CCU Resources. Note that the assumption here is that there is no congestion between the Resource Connectivity Node of the CCU and the Resource Node.

i. RTM SPP for the CCP Logical Resource Node is the Base Point or time weighted average of RTM LMPs at Logical Resource Node.

5. Private Use Network (PUN) Modeling

5.1 PUN Resource Node

a. The placement of a PUN Resource Node is optional. At a PUN, after all the Generation~~/Energy Storage~~ Resource Nodes, CCP Logical Resource Nodes and CCU Resource Nodes are placed (if applicable), if none of the Generation~~/Energy Storage~~ Resource Nodes or CCU Resource Nodes are placed where the EPS Meter is effectively located, then this is the location of the PUN Resource Node.

b. PUN Resource Node represents the Electrical Bus where an EPS Meter is effectively located that is measuring the flow at a POI with ERCOT.

c. PUN Resource Node is a Settlement Point.

d. PUN Resource Node cannot have mapped PUN Generation Resources or PUN ESRs.

e. There can be several PUN Resource Nodes for one PUN.

f. Only PTP Obligation Bids, ~~and~~ DAM Energy Bids, and DAM Energy-Only Offers can be submitted at a PUN Resource Node.

g. For DAM Energy-Only Offers, power is injected at the Electrical Bus of the PUN Resource Node.

h. Cleared quantities are settled at PUN Resource Node Settlement Prices.

[OBDRR046: Replace Section 5.1 above with the following upon system implementation of NPRR1188:]

5.1 PUN Resource Node

a. The placement of a PUN Resource Node is optional. At a PUN, after all the Generation/CLR Resource Nodes, CCP Logical Resource Nodes and CCU Resource Nodes are placed (if applicable), if none of the Generation/CLR Resource Nodes or CCU Resource Nodes are placed where the EPS Meter is effectively located, then this is the location of the PUN Resource Node.

b. PUN Resource Node represents the Electrical Bus where an EPS Meter is effectively located that is measuring the flow at a POI with ERCOT.

c. PUN Resource Node is a Settlement Point.

d. PUN Resource Node cannot have mapped PUN Generation~~/CLR~~ Resources, ESRs, or CLRs.

e. There can be several PUN Resource Nodes for one PUN.

f. Only PTP and DAM Energy Bids and Energy-Only Offers can be submitted at a PUN Resource Node.

g. For DAM Energy-Only Offers, power is injected at the Electrical Bus of the PUN Resource Node.

h. DAM Cleared quantities are settled at PUN Resource Node SPP.

5.2 Resource Nodes for PUN Generation Resources and PUN ESRs

a. The Resource Connectivity Node for a PUN Generation Resource or a PUN ESR represents the Electrical Bus where the physical Resource is connected.

b. Generator~~/ESR~~ outputs are injected at Resource Connectivity Nodes.

c. The Resource Node for a PUN Generation Resource or a PUN ESR represents the Electrical Bus where the Settlement Point for the PUN Generation Resource or PUN ESR is located.

d. The Resource Node for a PUN Generation Resource or a PUN ESR is defined using First Fork Rule and others as described in Section 3.2, Resource Node Location, above.

e. A Resource Node for a PUN Generation Resource or a PUN ESR is a Settlement Point.

f. PUN energy offers represent the net to grid in respect to PUN self-served load.

g. Three-Part Supply Offers~~, including~~ Energy Bid/Offer Curves, and Ancillary Service Offers can be submitted for a PUN Generation Resource or a PUN ESR for the excess capacity and energy not used to serve the PUN self-serve Load.

h. DAM Resource-~~S~~specific ~~O~~offers for PUN Generation Resources or PUN ESRs are settled at SPPs at Resource Nodes for PUN Generation Resources and PUN ESRs.

i. Constraints within a PUN can be monitored but will not be enforced by DAM, Reliability Unit Commitment (RUC) and Security-Constrained Economic Dispatch (SCED).

j. Only PTP Obligation Bids, ~~and~~ DAM Energy Bids, and DAM Energy-Only Offers can be submitted at PUN Resource Nodes.

[OBDRR046: Replace Section 5.2 above with the following upon system implementation of NPRR1188:]

5.2 Resource Nodes for PUN Generation Resources, PUN ESRs, and ~~/~~PUN CLRs

a. The Resource Connectivity Node for a PUN Generation Resource, PUN ESR, or ~~/~~PUN CLR represents the Electrical Bus where the physical Resource is connected or the Connectivity Node of the CIM Load that the CLR is mapped to.

b. Generator outputs are injected at Resource Connectivity Nodes and CLR consumption is withdrawn at the Resource Connectivity Nodes.

c. The Resource Node for a PUN Generation Resource, PUN ESR, or ~~/~~PUNCLR represents the Electrical Bus where the Settlement Point for the PUN Generation Resource, PUN ESR, or ~~/~~PUN CLR is located.

d. The Resource Node for a PUN Generation Resource, PUN ESR, or ~~/~~PUN CLR is defined using First Fork Rule and others as described in Section 3.2, Resource Node Location, above.

e. A Resource Node for a PUN Generation Resource, PUN ESR, or ~~/~~PUN CLR is a Settlement Point.

f. PUN energy offers represent the net to grid in respect to PUN self-served load excluding CLR energy consumption. PUN CLR Energy Bid Curves represent the bid to buy of the CLR total energy consumption.

g. Three-Part Supply Offers, Energy Bid /Offer Curves and Ancillary Service Offers can be submitted for a PUN Generation Resource, PUN ESR, or PUN CLR for the excess capacity and energy not used to serve the PUN self-serve Load. CLR Energy Bid Curves and Ancillary Service Offers can be submitted for PUN CLR for its total capacity.

h. DAM Resource-S~~s~~pecific ~~Energy~~ Offers ~~Curves and Energy Bid Curves~~ for PUN Generation Resources, PUN ESRs, and ~~/~~PUN CLRs are settled using SPPs at Resource Nodes for PUN Generation Resources, PUN ESRs, and ~~/~~PUN CLRs.

i. Constraints within a PUN can be monitored but will not be enforced by DAM, Reliability Unit Commitment (RUC) and Security-Constrained Economic Dispatch (SCED).

j. Only PTP Obligation Bids, ~~and~~ DAM Energy Bids, and DAM Energy-Only Offers can be submitted at PUN Resource Nodes.

5.3 CCP Modeling within a PUN

a. CCP trains within a PUN are treated in the same way as any CCP within ERCOT.

6. Settlement Points

a. Settlement Point is a Resource Node, Load Zone, or Hub.

b. Resource Nodes include Generation~~/Energy Storage~~ Resource Nodes, CCP Logical Resource Nodes, CCU Resource Nodes and PUN Resource Nodes.

c. Generation~~/Energy Storage~~ Resource Nodes within ERCOT as well as within PUNs are Settlement Points.

[OBDRR046: Replace Section 6 above with the following upon system implementation of NPRR1188:]

6. Settlement Points

a. Settlement Point is a Resource Node, Load Zone, or Hub.

b. Resource Nodes include Generation/CLR Resource Nodes, CCP Logical Resource Nodes, CCU Resource Nodes, and PUN Resource Nodes.

c. Generation/CLR Resource Nodes within ERCOT as well as within PUN are Settlement Points.

7. DAM Clearing and Settlements

a. PTP bids can be submitted using any Settlement Point (except Generation~~/Energy Storage~~ Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation~~/Energy Storage~~ Resource Node and EPS Meter; and CCP Logical Resource Nodes) as a source and sink.

b. CRRs acquired at de-energized Settlement Points will not be considered by Simultaneous Feasibility Test (SFT) function.

c. DAM Energy-Only Offers can be submitted at any Settlement Point (except Generation~~/Energy Storage~~ Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation~~/Energy Storage~~ Resource Node and EPS Meter; and CCP Logical Resource Nodes).

d. DAM Resource-specific energy offers that are submitted are mapped to a Generation~~/Energy Storage~~ Resource Node or a CCP Logical Resource Node only.

e. DAM Energy Bids can be submitted at Load Zones, Hubs, Generation~~/Energy Storage~~ Resource Nodes, CCU Resource Nodes and PUN Resource Nodes, i.e. at any Settlement Point except Generation~~/Energy Storage~~ Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation~~/Energy Storage~~ Resource Node and EPS Meter; and CCP Logical Resource Nodes.

f. DAM~~/Supplemental Ancillary Services Market (SASM)~~ Resource-Specific Ancillary Service Offers are ~~Generation/Load Resource-specific, not Settlement Point-specific.~~linked to the Resource, not to the Settlement Point.

g. DAM scheduling determines hourly quantities for PTPs, ~~E~~energy ~~B~~bids, ~~E~~energy ~~O~~offers, Energy Bid/Offer Curves, ~~energy and~~and Ancillary Service Offers~~ and bids~~.

h. DAM pricing determines hourly LMPs for all Settlement Points.

i. DAM Settlements ~~is~~are based on DAM quantities and DAM SPPs.

[OBDRR046: Replace Section 7 above with the following upon system implementation of NPRR1188:]

7. DAM Clearing and Settlements

a. PTP bids can be submitted using any Settlement Point (except Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the

Generation/CLR Resource Node and EPS Meter; and CCP Logical Resource Nodes) as a source and sink.

b. CRRs acquired at de-energized Settlement Points will not be considered by Simultaneous Feasibility Test (SFT) function.

c. DAM Energy-Only Offers can be submitted at any Settlement Point (except Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter; and CCP Logical Resource Nodes).

d. DAM Resource-specific energy offers that are submitted are mapped to a Generation/CLR Resource~~/CLR~~ Node or a CCP Logical Resource Node only.

e. DAM Energy Bids can be submitted at Load Zones, Hubs, Generation/CLR Resource Nodes, CCU Resource Nodes and PUN Resource Nodes, i.e., at any Settlement Point except Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter; and CCP Logical Resource Nodes.

f. DAM~~/Supplemental Ancillary Services Market (SASM)~~ Resource Specific Ancillary Service Offers are ~~Generation/Load Resource-specific, not Settlement Point-specific~~linked to the Resource, not to the Settlement Point.

g. DAM scheduling determines hourly quantities for PTPs, energy bids, energy offers, Energy Bid/Offer Curves, and Ancillary Service Offers~~ and bids~~.

h. DAM pricing determines hourly LMPs for all Settlement Points.

i. DAM Settlements ~~is~~are based on DAM quantities and DAM SPPs.

8. RTM Clearing and Settlements

a. SCED dispatch determines Base Points for Generation Resources and ESRs.

b. SCED pricing determines LMPs for all Generation~~/Energy Storage~~ Resource Nodes, CCP Logical Resource Nodes, CCU Resource Nodes, PUN Resource Nodes and all EPS Meter locations. SCED pricing determines MCPCs for AS types.

c. RTM determines 15-minute SPPs for each Settlement Point and each EPS Meter location. These prices are the Base Point-weighted and time-weighted average of the Real-Time LMPs.

d. RTM Settlements uses 15-minute RTM SPPs (prices at Settlement Points) and Settlement Prices (prices at EPS Meter locations).

e. RTM Energy Settlement for the measured output from the Generation Resources and ESRs uses the prices at the EPS Meter locations as specified in Protocol Section 6.6.3, Real-Time Energy Charges and Payments.

f. RTM Resource-Specific Ancillary Service Offers are linked to the Resource~~-specific~~, not to the Settlement Point~~-specific~~.

[OBDRR046: Replace Section 8 above with the following upon system implementation of NPRR1188:]

8. RTM Clearing and Settlements

a. SCED dispatch determines Base Points for Generation Resources, ESRs, and ~~/~~CLRs.

b. SCED pricing determines LMPs for all Generation/CLR Resource Nodes, CCP Logical Resource Nodes, CCU Resource Nodes, PUN Resource Nodes and all EPS Meter locations. SCED pricing determines MCPCs for Ancillary Service types.

c. RTM determines 15-minute SPPs for each Settlement Point and each EPS Meter location. These prices are the Base Point weighted and time weighted average of the Real-Time LMPs.

d. RTM Settlement uses 15-minute RTM SPPs (prices at Settlement Points) and Settlement prices (prices at EPS Meter locations).

e. RTM Energy Settlement for the measured output from the Generation Resources and ESRs uses the prices at the EPS Meter locations as specified in Protocol Section 6.6.3, Real-Time Energy Charges and Payments.

f. RTM Energy Settlement for the measured consumption from the CLRs uses the prices at the EPS Meter locations as specified in Protocol Section 6.6.3, Real-Time Energy Charges and Payments.

g. RTM Resource-Specific Ancillary Service Offers are linked to the Resource, not to the Settlement Point.

9. Summary of Allowed Activities

	ACTIVITIES					
Settlement Points	**Three-Part Supply Offer ~~(includes~~and Energy Bid/Offer Curve~~)~~**	**Ancillary Service Offer**	**DAM Energy-Only Offers**	**DAM Energy Bid**	**PTP bids (both in DAM & CRR**)**	**QSE to QSE Transaction**
Generation~~/Energy Storage~~ Resource Node not in a PUN site, or Generation~~/Energy Storage~~ Resource Node at a PUN where no constrainable Transmission Element(s) exist between the	Yes	Yes	Yes	Yes	Yes	Yes

Generation~~/Energy Storage~~ Resource Node and EPS Meter						
Generation~~/Energy Storage~~ Resource Node within a PUN site* where constrainable Transmission Element(s) exist between the Generation~~/Energy Storage~~ Resource Node and EPS Meter	Yes	Yes	No	No	No	Yes
CCU Resource Node	No	No	Yes	Yes	Yes	Yes
PUN Resource Node	No	No	Yes	Yes	Yes	Yes
CCP Logical Resource Node	Yes	Yes	No	No	No	No

Note that Resource-specific offers (Three-Part Supply Offers, ~~including~~ Energy Bid/Offer Curves, and Ancillary Service Offers) are made for the Resource and the submittal does NOT specify a Resource Node.

*These Generation~~/Energy Storage~~ Resource Nodes will be identified as such in the report NP4-500-SG, Day-Ahead Power System Simulator for Engineering (PSS/E) Network Operations Model and Supporting Files. CRR Auctions will use the most recent report available at the time the CRR Auction model is created.

**Generation~~/Energy Storage~~ Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation~~/Energy Storage~~ Resource Node and EPS Meter will become non-biddable in CRR Auctions for CRR effective dates after December 31, 2020.

[OBDRR046: Replace Section 9 above with the following upon system implementation of NPRR1188:]

9. Summary of Allowed Activities

	ACTIVITIES						
Settlement Points	**Three-Part Supply Offer and Energy**	**Ancillary Service Offer**	**DAM Energy-Only Offers**	**DAM Energy Bid**	**PTP bids (both in DAM & CRR**)**	**QSE to QSE Transaction**	**Energy Bid Curve**

	Bid/Offer Curve						
Generation/CLR Resource Node not in a PUN site, or Generation/CLR Resource Node at a PUN where no constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Generation/CLR Resource Node within a PUN site* where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter	Yes	Yes	No	No	No	Yes	Yes
CCU Resource Node	No	No	Yes	Yes	Yes	Yes	No
PUN Resource Node	No	No	Yes	Yes	Yes	Yes	No
CCP Logical Resource Node	Yes	Yes	No	No	No	No	No

Note that Resource-specific offers (Three-Part Supply Offers, Energy Bid/Offer Curves, Energy Bid Curve, and Ancillary Service Offers) are made for the Resource and the submittal does NOT specify a Resource Node.

*These Generation/CLR Resource Nodes will be identified as such in the report NP4-500-SG, Day-Ahead Power System Simulator for Engineering (PSS/E) Network Operations Model and Supporting Files. CRR Auctions will use the most recent report available at the time the CRR Auction model is created.

**Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter will become non-biddable in CRR Auctions for CRR effective dates after December 31, 2020.

ERCOT Impact Analysis Report

OBDRR Number	052	OBDRR Title	Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
Impact Analysis Date	July 31, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Other Binding Document Revision Request (OBDRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1246, Energy Storage Resource Terminology Alignment for the Single-Model Era.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this OBDRR beyond what was captured in the Impact Analysis for NPRR1246.

Board Report

PGRR Number	117	PGRR Title	**Addition of Resiliency Assessment and Criteria to Reflect PUCT Rule Changes**
Date of Decision	February 4, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $360k and $440k (Annual Recurring O&M) Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Planning Guide Sections Requiring Revision	2.2, ACRONYMS AND ABBREVIATIONS 3.1.1.6, Grid Reliability and Resiliency Assessment (new) 4.1, Introduction 4.1.2, Resiliency Criteria (new)		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Planning Guide Revision Request (PGRR) revises the Planning Guide to reflect the PUCT's rulemaking addition of subsection (b)(3)(E) to 16 Texas Administrative Code (TAC) § 25.101, *Certification Criteria*, which requires ERCOT to conduct a biennial assessment of the ERCOT power grid's reliability and resiliency in extreme weather scenarios and permits ERCOT to recommend transmission projects to address resiliency issues identified in the assessment. ERCOT intends to perform the biennial assessment in parallel with the Regional Transmission Plan (RTP) process.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers		

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	☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s) ☒ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	These revisions to the Planning Guide reflect ERCOT's intended implementation of rulemaking amendments to 16 TAC § 25.101 that went into effect on December 20, 2022. Specifically, § 25.101(b)(3)(E) requires ERCOT to conduct a biennial assessment of the power grid's reliability and resiliency in extreme weather scenarios and specifies that the assessment must: (i) consider the impact of different levels of thermal and renewable generation availability; (ii) identify areas of the state that face significant grid reliability and resiliency issues, taking into account the impact of potential outages caused by regional extreme weather scenarios on customers, including multiple element outage analysis when appropriate, and; (iii) recommend transmission projects that may increase the grid's reliability or resiliency in extreme weather scenarios. Furthermore, § 25.101(b)(3)(A)(iii) establishes that ERCOT may recommend a transmission project that would address a resiliency issue identified in the grid reliability and resiliency assessment. ERCOT intends to propose a Nodal Protocol Revision Request (NPRR) to address the process for determining whether an upgrade that meets the proposed resiliency criteria provides sufficient benefit to offset any insufficiency of economic savings or reliability benefits, as provided in 16 TAC § 25.101(b)(3)(A)(iii). ERCOT believes this determination is best suited for consideration as part of the Regional Planning Group (RPG) Project Review process.
ROS Decision	On 8/1/24, ROS voted unanimously to table PGRR117 and refer the issue to the Planning Working Group (PLWG). All Market Segments participated in the vote. On 11/7/24, ROS voted unanimously to recommend approval of PGRR117 as amended by the 10/11/24 ERCOT comments. All Market Segments participated in the vote.

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	On 12/5/24, ROS voted unanimously to endorse and forward to TAC the 11/7/24 ROS Report and the 7/17/24 Impact Analysis for PGRR117. All Market Segments participated in the vote.
Summary of ROS Discussion	On 8/1/24, ERCOT provided an overview of PGRR117. Participants requested to table PGRR117 and refer it to PLWG for further review. On 11/7/24, participants reviewed the 10/11/24 ERCOT comments. On 12/5/24, participants reviewed the 7/17/24 Impact Analysis for PGRR117.
TAC Decision	On 1/22/25, TAC voted unanimously to recommend approval of PGRR117 as recommended by ROS in the 12/5/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 1/22/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 2/4/25, the ERCOT Board voted unanimously to recommend approval of PGRR117 as recommended by TAC in the 1/22/25 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on PGRR117.
ERCOT Opinion	ERCOT supports approval of PGRR117.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR117 and believes the market impact of PGRR117 is it aligns the Planning Guide with subsection (b)(3)(E) to 16 Texas Administrative Code (TAC) § 25.101,

Board Report

	Certification Criteria, which requires ERCOT to conduct a biennial assessment of the ERCOT power grid's reliability and resiliency in extreme weather scenarios and permits ERCOT to recommend transmission projects to address resiliency issues identified in the assessment.

Sponsor	
Name	Robert Golen
E-mail Address	robert.golen@ercot.com
Company	ERCOT
Phone Number	512-248-6702
Cell Number	518-813-6455
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Erin Wasik-Gutierrez
E-Mail Address	erin.wasik-gutierrez@ercot.com
Phone Number	413-886-2474

Comments Received	
Comment Author	**Comment Summary**
LCRA 092324	Revised language to reflect discussions at the 8/13/24 Planning Working Group (PLWG) meeting
ERCOT 101124	Retained reference to "coincident load values", clarified the study case will be adjusted to have sufficient power supply to meet demand and replaced references to "load shedding" with "outages" to align with the language in 16 TAC § 25.101

Market Rules Notes

Please note that the following PGRR(s) also propose revisions to the following section(s):

- PGRR118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 4.1

Board Report

Please note that the baseline Planning Guide language in the following sections has been updated to reflect the incorporation of the following PGRR(s) into the Planning Guides:

- PGRR116, Related to NPRR1240, Access to Transmission Planning Information (incorporated 2/1/25)
  - Section 4.1

Revised Proposed Guide Language

2.2 ACRONYMS AND ABBREVIATIONS

CY	Current Year
FIS	Full Interconnection Study
FY	Future Year
GIC	Geomagnetically-Induced Current
GIM	Generator Interconnection or Modification
GINR	Generation Interconnection or Change Request
GMD	Geomagnetic Disturbance
GRRA	Grid Reliability and Resiliency Assessment
LTSA	Long-Term System Assessment
RIOO	Resource Integration and Ongoing Operations
SSR	Subsynchronous Resonance

TCEQ Texas Commission on Environmental Quality

3.1.1.6 Grid Reliability and Resiliency Assessment (GRRA)

(1) ERCOT shall perform the Grid Reliability and Resiliency Assessment (GRRA) in coordination with the Regional Planning Group (RPG) on a biennial basis in even-numbered years to assess the reliability and resiliency of the ERCOT System ~~reliability and resiliency~~ in extreme weather scenarios. The study ~~must~~shall:

(a) Consider the impact of different levels of thermal and renewable generation availability;

(b) Identify areas of the ERCOT Region that face significant grid reliability and resiliency issues, taking into account the impact of potential Outages caused by regional extreme weather scenarios on Customers; and

(c) Identify transmission upgrades that are expected to increase the reliability or resiliency of the ERCOT System in extreme weather scenarios based on the criteria established in Section 4.1.2, Resiliency Criteria.

(2) Extreme weather scenarios shall be selected for one or more study cases. The study cases prepared will be adjusted to have sufficient power supply to meet the demand. The study

cases shall be based on the current Regional Transmission Plan study cases, utilizing coincident load values, and ~~use coincident load values and the selected scenarios~~ may include scenarios that vary one or more of the following modeling assumptions:

(a) Different patterns of generation;

(b) Extreme peak load;

(c) Multiple Transmission Element Outages; and/or

(d) Multiple Generation Resource Outages.

(3) Under the extreme weather study scenarios described in paragraph (2) above, the post-contingency performance of the ERCOT System shall be evaluated for the following contingency events:

(a) ~~c~~Categories P0, P1, and P2.1 ~~and P7 of~~ as defined in NERC Reliability Standard TPL-001; and ~~shall be evaluated.~~

(b) Common tower outages as defined in Section 4.1.1.1, Planning Assumptions. ~~The study cases prepared for evaluating P0 events will be adjusted to have sufficient power supply to meet the demand in each case.~~

4.1 Introduction

Commented [EWG1]: Please note PGRR 118 also proposes revisions to this section.

(1) ERCOT employs ~~both~~ reliability, ~~criteria and~~ economic, and resiliency criteria in evaluating the need for transmission system improvements. The economic criteria are included in Protocol Section 3.11.2, Planning Criteria. This Planning Guide provides the reliability and resiliency criteria.

(2) The ERCOT System consists of those generation and Transmission Facilities (60 kV and higher voltages) that are controlled by individual Market Participants and that function as part of an integrated and coordinated system.

(3) To maintain reliable operation of the ERCOT System, it is necessary that all stakeholders observe and subscribe to certain minimum planning criteria. The criteria set forth in this Section 4.1 constitute the aforementioned minimum planning criteria. Tests outlined herein shall be performed to determine conformance to these minimum criteria; however, ERCOT recognizes that events more severe than those outlined in these criteria could cause grid separation and other tests may also be performed.

(4) The complexity and uncertainty inherent in the planning and operation of the ERCOT System make exhaustive studies impracticable; therefore, to gain maximum benefit from the limited number of tests performed, the selection of the specific tests and the frequency of their performance will be made solely upon the basis of the expected value of the reliability information obtainable from the test.

(5) ERCOT shall perform steady-state, short circuit, and dynamic analyses appropriate to ensure the reliability of the ERCOT System and identify appropriate solutions.

(6) Each Transmission Service Provider (TSP) will perform steady-state, short circuit, and dynamic analyses appropriate to ensure the reliability of its portion of the ERCOT System and implement appropriate solutions to meet the reliability performance criteria in this Section 4.1.

(7) The base cases created by the Steady-State Working Group (SSWG) and System Protection Working Group (SPWG) are available for use by Market Participants.

(8) If a TSP has its own planning criteria in addition to those defined in this Planning Guide, the TSP shall provide documentation of those criteria to ERCOT. ERCOT shall post the documentation on the Market Information System (MIS) Secure Area. The TSP shall notify ERCOT of any changes to their planning criteria and provide revised documentation within 30 days of such change.

[PGRR116: Replace paragraph (8) above with the following upon system implementation of NPRR1240:]

(8) If a TSP has its own planning criteria in addition to those defined in this Planning Guide, the TSP shall provide documentation of those criteria to ERCOT. ERCOT shall post the documentation on the ERCOT website. The TSP shall notify ERCOT of any changes to their planning criteria and provide revised documentation within 30 days of such change.

4.1.2 Resiliency Criteria

(1) As part of ~~a~~the resiliency analysis ~~as~~ described in Planning Guide Section 3.1.1.6, Grid Reliability and Resiliency Assessment (GRRA), ERCOT shall identify ~~a need for only~~ those transmission upgrades that are necessary to:

(a) Prevent cascading, instability, or uncontrolled islanding; and/or

(b) Reduce the impact ~~and duration~~ of ~~load shedding~~~~load loss~~outages on customers.

ERCOT Impact Analysis Report

PGRR Number	**117**	**PGRR Title**	**Addition of Resiliency Assessment and Criteria to Reflect PUCT Rule Changes**
Impact Analysis Date	July 17, 2024		
Estimated Cost/Budgetary Impact	None. Annual Recurring Operations and Maintenance (O&M) Budget Cost: Between $360k and $440k See ERCOT Staffing Impacts		
Estimated Time Requirements	No project required. This Planning Guide Revision Request (PGRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	There will be ongoing operational impacts to the following ERCOT department totaling 2.0 Full-Time Employees (FTEs) to support this PGRR: • Regional Transmission Planning (2.0 FTEs Effort) ERCOT has assessed its ability to absorb the ongoing efforts of this PGRR with current staff and concluded the need for two additional FTEs in the Regional Transmission Planning department. * 3720 hours – to perform the biennial Grid Reliability and Resiliency study using the defined resiliency criteria. These 2 additional FTEs are included in the ERCOT 2024-2025 approved budget.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this PGRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

ERCOT Impact Analysis Report

Comments
None.

Board Report

PGRR Number	118	PGRR Title	Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
Date Posted		February 4, 2025	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		Upon implementation of Nodal Protocol Revision Request (NPRR) 1246, Energy Storage Resource Terminology Alignment for the Single-Model Era	
Priority and Rank Assigned		Not applicable	
Planning Guide Sections Requiring Revision		2.1, Definitions 3.1.1.3, Regional Planning Group Project Reviews 3.1.1.4, Generation Interconnection Process 3.1.2.1, All Projects 3.1.3, Project Evaluation 3.1.3.1, Definitions of Reliability-Driven and Economic-Driven Projects 3.1.4, Regional Transmission Plan Development Process 3.1.4.1, Development of Regional Transmission Plan 3.1.4.1.1, Regional Transmission Plan Cases 3.1.8, Planning Geomagnetic Disturbance Activities 3.1.9, Transmission Interconnection Study 4.1, Introduction 4.1.1.1, Planning Assumptions 5, Generator Interconnection or Modification 5.2.1, Applicability 5.3, Interconnection Study Procedures for Large Generators 5.3.1, Security Screening Study 5.3.2, Full Interconnection Study 5.3.2.1, Proof of Site Control 5.3.2.3, Full Interconnection Study Description and Methodology 5.3.2.4.1, Steady-State Analysis 5.3.5, ERCOT Quarterly Stability Assessment 6.1, Steady-State Model Development 6.2, Dynamics Model Development 6.2.1, Dynamics Data Requirements for Generation Resources and Settlement Only Generators 6.3, Process for Developing Short Circuit Cases	

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	6.8, Resource Registration Procedure 6.8.1, Resource Registration 6.8.2, Resource Registration Process 6.9, Addition of Proposed Generation to the Planning Models 6.11, Process for Developing Geomagnetically-Induced Current (GIC) System Models 7.1, Planning Data Information Section 8 Attachment B, Declaration of Adequate Water Supplies Section 8 Attachment C, Declaration of Department of Defense Notification
Related Documents Requiring Revision/Related Revision Requests	Nodal Operating Guide Revision Request (NOGRR) 268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era NPRR1246 Other Binding Document Revision Request (OBDRR) 052, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
Revision Description	This Planning Guide Revision Request (PGRR) inserts terminology associated with Energy Storage Resources (ESRs) in the appropriate places throughout the Planning Guide, aligning provisions and requirements for ESRs with those already in place for Generation Resources and Controllable Load Resources. While several key sections of the Planning Guides have already been modified to accommodate ESRs in the "combo model" era — in which ESRs are treated as two Resources — numerous other provisions and requirements rely on the blanket provision from NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions, in paragraph (1) of Protocol Section 3.8.5, Energy Storage Resources, as follows: "For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise." As discussed at meetings in 2020 of the Battery Energy Storage Task Force (BESTF), ERCOT intended for this provision to be temporary, and explained to stakeholders that it would introduce an NPRR and related Revision Requests that incorporated the ESR terminology in all appropriate locations in the Nodal Protocols. This PGRR accomplishes that objective in the Planning Guide.

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	This PGRR is applicable to ESRs in the future single-model era and should be implemented simultaneously with NPRR1246 and NPRR1014, BESTF-4 Energy Storage Resource Single Model. ERCOT invites review of this PGRR from the Real-Time Co-Optimization plus Batteries Task Force (RTCBTF) and any other applicable groups. It is also worth noting these changes have no system impacts as they reflect the current RTC+B business requirements and interface requirements for Market Participants.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This PGRR improves transparency and ease of access to provisions and requirements for ESR developers and Market Participants. With the implementation of this PGRR at the time of RTC+B go-live, all references to the Combo-Model will be removed.
ROS Decision	On 9/9/24, ROS voted unanimously to table PGRR118. All Market Segments participated in the vote. On 10/3/24, ROS voted unanimously to recommend approval of PGRR118 as amended by the 9/20/24 ERCOT comments. All Market Segments participated in the vote. On 11/7/24, ROS unanimously voted to endorse and forward to TAC the 10/3/24 ROS Report and 7/31/24 Impact Analysis for PGRR118. All Market Segments participated in the vote.
Summary of ROS Discussion	On 9/9/24, ERCOT Staff provided an overview of PGRR118 and expressed a desire for approval of these related Revision Requests

	prior to go-live of the RTC+B project. Participants requested tabling of PGRR118 for additional review. On 10/3/24, ERCOT Staff presented the 9/20/24 ERCOT comments. On 11/7/24, there was no discussion.
TAC Decision	On 11/20/24, TAC voted unanimously to recommend approval of PGRR118 as recommended by ROS in the 11/7/24 ROS Report. All Market Segments participated in the vote. On 1/22/25, TAC voted unanimously to recommend approval of PGRR118 as recommended by TAC in the 11/20/24 TAC Report as amended by the 1/21/25 ERCOT comments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, there was no additional discussion beyond TAC review of the items below. On 1/22/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to remand PGRR118 to TAC. On 2/4/25, the ERCOT Board voted unanimously to recommend approval of PGRR118 as recommended by TAC in the 1/22/25 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on PGRR118.
ERCOT Opinion	ERCOT supports approval of PGRR118.

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ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR118 and believes the market impact for PGRR118 provides clarity and additional transparency for stakeholders on the applicable provisions and requirements associated with ESRs as the market transitions from the combo model to the single model as part of the RTC+B project.

Sponsor	
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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**
ERCOT 092024	Proposed edits removing certain initially proposed additions of the term “energy storage” throughout PGRR118
ERCOT 012125	Proposed additional edits to align with PGRR112, Dynamic Data Model and Full Interconnection Study (FIS) Deadline for Quarterly Stability Assessment

Market Rules Notes

Please note the baseline language in the following sections has been updated to reflect the incorporation of the following PGRRs into the Planning Guide:

- PGRR113, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations (incorporated 8/1/24)
    - Section 3.1.4.1.1

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- PGRR098, Consideration of Load Shed in Transmission Planning Criteria (unboxed 8/1/24)
  - Section 4.1.1.1
- PGRR107, Related to NPRR1180, Inclusion of Forecasted Load in Planning Analyses (incorporated 2/1/25)
  - Section 3.1.2.1
  - Section 3.1.3
  - Section 4.1.1.1
- PGRR108, Related to NPRR1183, ECEII Definition Clarification and Updates to Posting Rules for Certain Documents without ECEII (unboxed 12/12/24)
  - Section 3.1.8
  - Section 7.1
- PGRR112 (unboxed 12/1/24)
  - Section 5.3.5
- PGRR116, Related to NPRR1240, Access to Transmission Planning Information (incorporated 2/1/25)
  - Section 4.1
  - Section 7.1

Please note that the following PGRR(s) also propose revisions to the following section(s):

- PGRR115, Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  - Section 4.1.1.1
  - Section 5.3.5
- PGRR117, Addition of Resiliency Assessment and Criteria to Reflect PUCT Rule Changes
  - Section 4.1
- PGRR119, Stability Constraint Modeling Assumptions in the Regional Transmission Plan
  - Section 3.1.4.1.1
- PGRR121, Related to NOGRR272, Advanced Grid Support Requirements for Inverter-Based ESRs
  - Section 6.2

Proposed Guide Language Revision

2.1 DEFINITIONS

Manual System Adjustment

Operator actions, with consequences allowed by Section 4, Transmission Planning Criteria, in response to an outage in the ERCOT System, including, but not limited to circuit switching or changes to schedules of Generation Resources and Energy Storage Resources (ESRs), but excluding the physical repair or replacement of any damaged equipment.

3.1.1.3 Regional Planning Group Project Reviews

(1) Except for minor transmission projects that have only localized impacts and projects that are directly associated with the interconnection of new Generation Resources and Energy Storage Resources (ESRs), all transmission projects in the ERCOT Region undergo a formal review by the RPG in accordance with Protocol Section 3.11.4, Regional Planning Group Project Review Process. In addition, ERCOT performs an independent analysis of the need for major transmission projects that are submitted for RPG Project Review. The affirmative result of this review is formal endorsement of the project by ERCOT. This ERCOT project endorsement is intended to support, to the extent applicable, a finding by the Public Utility Commission of Texas (PUCT) that a project is necessary for the service, accommodation, convenience, or safety of the public within the meaning of Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 37.056 (Vernon 1998 and Supp. 2007) and P.U.C. SUBST. R. 25.101, Certification Criteria.

3.1.1.4 Generation ~~and Energy Storage~~ Interconnection Process

(1) This process facilitates the interconnection of new generation ~~and energy storage~~ units in the ERCOT Region by assessing the transmission upgrades necessary for new ~~generating~~ generating units to operate reliably. The process to study interconnecting new generation ~~or energy storage,~~ or modifying an existing generation ~~or energy storage~~ interconnection to the ERCOT Transmission Grid, is covered in Section 5, Generator~~/Energy Storage System~~ Interconnection or Modification. The ~~generation~~ generation interconnection study process primarily covers the direct connection of generation ~~and energy storage~~ Facilities to the ERCOT Transmission Grid and directly-related projects. Additional upgrades to the ERCOT Transmission Grid that might be cost-effective as a result of new or modified generation ~~or energy storage~~ may be initiated by any stakeholder through the RPG Project Review procedure described in Protocol Section 3.11.4, Regional Planning Group Project Review Process, at the appropriate time, subject to the confidentiality provisions in Section 5.

3.1.2.1 All Projects

(1) The submittal of each transmission project (60 kV and above) for RPG Project Review should include the following elements:

(a) The proposed project description including expected cost, feasible alternative(s) considered, transmission topology and Transmission Facility modeling parameter data, and all study cases used to generate results supporting the need for the project in electronic format (powerflow data should be in PTI Power System Simulator for Engineering (PSS/E) RAWD format). Also, the submission should include accurate maps and one-line diagrams showing locations of the proposed project and feasible alternatives;

(b) Identification of the SSWG, Dynamics Working Group (DWG), or Regional Transmission Plan powerflow cases used as a basis for the study and any associated changes that describe and allow accurate modeling of the proposed project;

(c) Description and data for all changes made to the SSWG base cases or Regional Transmission Plan cases used to identify the need for the project, such as ~~Generation~~ Resource unavailability and area peak Load forecast;

(d) A description of the reliability and/or economic problem that is being solved;

(e) Information that supports any load values that differ from the load forecast used in the base cases identified in item (b) above, including any relevant historical load information or evidence demonstrating that a submitted load value is Substantiated Load;

(f) A description of the Subsynchronous Resonance (SSR) impact of the proposed project to the generation ~~or energy storage~~ ~~f~~Facilities in the system pursuant to Protocol Section 3.22.1, Subsynchronous Resonance Vulnerability Assessment, and potential SSR Countermeasure plan for any identified SSR vulnerability, if applicable;

(g) Desired/needed in-service date for the project, and feasible in-service date, if different;

(h) The phone number and email address of the single point of contact who can respond to ERCOT and RPG participant questions or requests for additional information necessary for stakeholder review; and

(i) Analysis of rejected alternatives, including cost estimates, and other factors considered in the comparison of alternatives with the proposed project.

(2) Both transmission and distribution solutions to performance deficiencies may be considered where applicable.

(3) If there is any other information, not included above, that the submitting party believes is relevant to consideration of the need for any submitted project, the submitting party should include that information in the project submission.

3.1.3 Project Evaluation

(1) ERCOT and the RPG shall evaluate proposed transmission projects using a variety of tools and techniques as needed to ensure that the system is able to meet applicable reliability criteria in a cost-effective manner. For most proposed projects, several alternatives will be identified to meet the reliability criteria or other performance improvement objectives that the proposed project is designed to meet. The project alternative with the expected lowest cost over the life of the project is generally recommended, subject to consideration of the expected long-term system needs in the

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area, including, as applicable, any evidence of Substantiated Load, and subject to consideration of the relative operational impacts of the alternatives.

(2) In some cases, one alternative may be to dispatch the system in such a way that all reliability requirements are met, even without the proposed transmission project or any transmission alternative, resulting in a less efficient dispatch than what would be required to meet the reliability requirements if the proposed project was in place. Consideration of the merits of this alternative relative to the proposed transmission project is more complex. To facilitate the discussion and consideration of these alternatives, ERCOT has adopted certain definitions and practices, described in paragraph (4) of Protocol Section 3.11.2, Planning Criteria, and Sections 3.1.3.1, Definitions of Reliability-Driven and Economic-Driven Projects, and 3.1.3.2, Reliability-Driven Project Evaluation below.

(3) In conducting an independent review of any project, ERCOT may, in its discretion, make adjustments to the planning case to ensure that the case reaches a solution. When conducting an independent review of any project classified as Tier 1 pursuant to Protocol Section 3.11.4, Regional Planning Group Project Review Process, ERCOT must provide reasonable advance notice to the RPG of any proposed adjustments and an opportunity for stakeholder comment on them.

(4) As part of its independent review of any project classified as Tier 1 pursuant to Protocol Section 3.11.4, ERCOT shall:

(a) Perform a generation~~/energy storage~~ sensitivity analysis. The ~~generation~~ generation sensitivity analysis will evaluate the effect that proposed Generation Resources and/or ~~Energy Storage Resources (~~ESRs~~)~~ in or near the study area will have on a recommended transmission project. Generation Resources and ESRs that have signed Standard Generation Interconnection Agreements (SGIAs) but were not included in the study cases because they did not meet all of the requirements for inclusion in the cases pursuant to Section 6.9, Addition of Proposed Generation~~ or Energy Storage~~ to the Planning Models, will be included in the sensitivity analysis. ERCOT shall not consider the results of the ~~generation~~ generation sensitivity analysis in determining project need during its independent review of the project; and

(b) Evaluate impacts related to the load scaling used in the study on any constraints resulting in project recommendations. The results of this evaluation shall be included in the final recommendations in the independent review.

(5) ERCOT's independent review shall incorporate and consider historical load and any Substantiated Load.

3.1.3.1 Definitions of Reliability-Driven and Economic-Driven Projects

(1) Proposed transmission projects are categorized for evaluation purposes into two types:

(a) Reliability-driven projects; and

(b) Economic-driven projects.

(2) The differentiation between these two types of projects is based on whether a simultaneously-feasible, security-constrained ~~generating~~ generating unit commitment and dispatch is expected to be available for all hours of the planning horizon that can resolve the system reliability issue that the proposed project is intended to resolve. If it is not possible to simulate a dispatch of the Generation Resources and ESRs such that all reliability criteria are met without the project, and the addition of the project allows the reliability criteria to be met, then the project is classified as a reliability-driven project. If it is possible to simulate a dispatch of the Generation Resources and ESRs in such a way that all reliability criteria are met without the project, but the project may allow the reliability criteria to be met at a lower total cost, then the project is classified as an economic-driven project. When performing a simulation of the ~~generating~~ generating unit commitment and dispatch, only contingencies and limits that would be considered in the operations horizon shall be simulated.

3.1.4 Regional Transmission Plan Development Process

(1) As prescribed by Section 3.1.1.2, Regional Transmission Plan, the purpose of the Regional Transmission Plan is to provide a coordinated plan for the ERCOT System. This Section describes the process used by ERCOT to develop the Regional Transmission Plan. While unanticipated changes in Load and ~~generationResources~~generation may require additional projects to be needed that were not included in the current Regional Transmission Plan, or require additional evaluation of projects included in the current Regional Transmission Plan when they are submitted for RPG Project Review, the Regional Transmission Plan provides a reasonable and supportable basis for analyses of the planned ERCOT Transmission Grid.

3.1.4.1 Development of Regional Transmission Plan

(1) The planning process begins with computer modeling studies of the ~~generation Resource~~ generation and Transmission Facilities and substation Loads under normal conditions in the ERCOT System. Contingency conditions along with changes in Load and ~~generationResources~~generation that might be expected to occur in operation of the ERCOT Transmission Grid are also modeled. To maintain adequate service and minimize interruptions during Outages, model simulations are used to identify adverse results based upon the planning criteria and to examine the effectiveness of various problem-solving alternatives.

(2) The effectiveness of each alternative will be evaluated under a variety of possible operating environments because Loads and operating conditions cannot be predicted with certainty. As a result, repeated simulations under different conditions are often required. In addition, options considered for future installation may affect other alternatives so that several different combinations must be evaluated, thereby multiplying the number of simulations required.

(3) Once feasible alternatives have been identified, the process is continued with a comparison of those alternatives. To determine the most favorable, the short-range and long-range benefits of each alternative must be considered including operating flexibility and compatibility with future plans.

3.1.4.1.1 Regional Transmission Plan Cases

Commented [CP1]: Please note PGRR119 also proposes revisions to this section.

(1) The starting base cases for the Regional Transmission Plan development are created by removing all Tier 1, 2, and 3 projects that have not received RPG acceptance or, if applicable, ERCOT endorsement from the most recent SSWG base cases.

(2) ERCOT shall set all non-seasonal Mothballed Generation Resources and Mothballed ESRs to out of service in the Regional Transmission Plan reliability base cases. ERCOT shall add proposed Generation Resources and ESRs that have met the criteria for inclusion in Section 6.9, Addition of Proposed Generation ~~of Energy Storage~~ to the Planning Models, to the Regional Transmission Plan base cases.

(3) ERCOT shall update the Regional Transmission Plan reliability and economic base cases to reflect any updates to the amount of Switchable Generation Resource (SWGR) capacity available to the ERCOT Region.

(4) ERCOT may, in its discretion, set a Generation Resource or ESR to out of service in the Regional Transmission Plan base cases prior to receiving a Notification of Suspension of Operations (NSO) if the Resource Entity notifies ERCOT of its intent to retire/mothball the ~~Generation~~ Resource and/or makes a public statement of its intent to retire/mothball the ~~Generation~~ Resource. ERCOT must provide reasonable advance notice to the RPG of any proposed ~~Generation~~ Resource retirements/mothballs and allow an opportunity for stakeholder comments.

(a) ERCOT will post and maintain the current list of Generation Resources and ESRs that will be set to out of service pursuant to paragraph (4) above on the ERCOT website.

(5) In its Regional Transmission Plan studies, ERCOT shall first consider transmission needs without Remedial Action Scheme (RAS) actions. After evaluating these needs, ERCOT may model a RAS in the Regional Transmission Plan cases only if ERCOT's initial studies did not identify a transmission project to exit the RAS or if a transmission project to exit the RAS is not expected to be in service by the season and year the case represents.

[PGRR113: Replace paragraph (5) above with the following upon system implementation of NPRR1198:]

(5) In its Regional Transmission Plan studies, ERCOT shall first consider transmission needs without Remedial Action Scheme (RAS) or Constraint Management Plan (CMP) actions. After evaluating these needs, ERCOT may model a RAS or CMP in the Regional Transmission Plan cases only if ERCOT's initial studies did not identify a

transmission project to exit the RAS or CMP, or if a transmission project to exit the RAS or CMP is not expected to be in service by the season and year the case represents.

(6) ERCOT may, in its discretion, make other adjustments to any Regional Transmission Plan base case to ensure that the case reaches a solution. ERCOT must provide reasonable advance notice to the RPG of any proposed adjustments and an opportunity for stakeholder comment on them.

3.1.8 Planning Geomagnetic Disturbance (GMD) Activities

(1) As required by the applicable NERC Reliability Standard, ERCOT shall employ the Geomagnetically-Induced Current (GIC) system models described in Section 6.11, Process for Developing Geomagnetically-Induced Current (GIC) System Models, to perform simulations to identify maximum effective GIC flow in the high side wye-grounded transformers for the worst case geoelectric field orientation for each transformer for the benchmark and supplemental Geomagnetic Disturbance (GMD) events. ERCOT shall post on the MIS Secure Area the preliminary maximum effective GIC flows and preliminary GIC time series results to the TSPs and Resource Entities for comment before finalizing the results. Upon consideration of the comments, ERCOT shall make the final maximum effective GIC flows in the high side wye-grounded transformers and the final GIC time series available to TSPs and Resource Entities by posting this data on the ERCOT MIS Secure Area.

(2) Each TSP and Resource Entity that owns a high side wye-grounded transformer(s) with the high side terminal operated at 200 kV or higher within the ERCOT planning area shall perform the benchmark and supplemental transformer thermal impact assessment(s) as required in the applicable NERC Reliability Standard and shall provide to ERCOT any suggested actions to mitigate the impact of GICs on those transformers with the high side terminal operated at 200 kV or higher within 18 months of the date of ERCOT notification to TSPs and Resource Entities that the final GIC flow results are posted on the MIS Secure Area.

(3) ERCOT and the TSPs shall develop for approval by the TAC, criteria for acceptable steady-state voltage performance during the benchmark and supplemental GMD events.

(4) ERCOT in collaboration with the TSPs and Resource Entities shall perform the ERCOT benchmark and supplemental GMD vulnerability assessments as required in the applicable NERC Reliability Standard; and may set a Generation Resource or ESR to out of service prior to receiving an NSO if the Resource Entity notifies ERCOT of its intent to retire/mothball the ~~Generation~~ Resource and/or makes a public statement of its intent to retire/mothball the ~~Generation~~ Resource. ERCOT shall post on the ERCOT website the preliminary results of the GMD vulnerability assessments to the TSPs and Resource Entities for comment before finalizing the results. Upon request, ERCOT shall make available to the TSPs the GIC system models and other model information used for the GMD vulnerability assessments, including suggested actions described in paragraph (2) above.

(a) ERCOT will post and maintain the current list of Generation Resources and ESRs that will be set to out of service pursuant to paragraph (4) above on the ERCOT website.

(5) ERCOT shall finalize the ERCOT benchmark and supplemental GMD vulnerability assessments, including any associated corrective action plans, post them as follows, and notify TSPs and Resource Entities of the posting:

(a) Versions that include ECEII shall be posted on the MIS Secure Area;

(b) Versions that include both ECEII and Protected Information shall be posted on the MIS Certified Area for TSPs only; and

(c) Versions redacted of ECEII and Protected Information shall be posted on the ERCOT website.

(6) For each GMD vulnerability assessment that does not satisfy applicable performance requirements, each impacted TSP and Resource Entity, in collaboration with ERCOT, shall develop and document corrective action plan(s) for their facilities, and develop a timetable, subject to revision, for implementing the corrective action plan(s). For any corrective action plan proposing upgrades to the transmission system that are subject to Protocol Section 3.11.4, Regional Planning Group Project Review Process, review shall be conducted in accordance with the process described therein. For any corrective action plan that is not subject to the review process described in Protocol Section 3.11.4, ERCOT shall review the corrective action plan to ensure that it satisfies applicable performance requirements. Any corrective action plan that proposes operational actions shall be reviewed pursuant to Nodal Operating Guide Section 11, Constraint Management Plans and Remedial Action Schemes.

(a) If a situation beyond the control of the TSP or Resource Entity prevents implementation of a corrective action plan within the timetable for implementation required in the applicable NERC Reliability Standard, the TSP or Resource Entity shall submit a revised corrective action plan, updated timetable, and documentation supporting the request for extension of time, as required in the applicable NERC Reliability Standard, to ERCOT within 30 days of the revision of the corrective action plan.

(b) After receipt of all information required in the applicable NERC Reliability Standard, ERCOT shall submit the request for extension of time to the NERC Regional Entity, as required in the applicable NERC Reliability Standard, on behalf of the TSP or Resource Entity.

(7) ERCOT shall post the GMD vulnerability assessment reports and corrective action plan(s) on the ERCOT MIS Secure Area within 90 calendar days of development or revision.

(8) ERCOT in collaboration with TSPs and Resource Entities shall implement a process for obtaining GIC monitor data and geomagnetic field data from TSPs, Resource Entities, or other available sources as required in the applicable NERC Reliability Standard.

3.1.9 Transmission Interconnection Study

(1) ERCOT shall perform an annual transmission interconnection study to analyze the reliability impact of any transmission projects 100 kV or above that are expected to be in-service before the completion of the next Regional Transmission Plan and were not included in the current Regional Transmission Plan, an RPG project submission, or a Generation Interconnection or Change Request (GINR) study pursuant to Section 5, Generator~~/Energy Storage System~~ Interconnection or Modification.

(a) ERCOT shall identify a list of transmission projects 100 kV or above that need to be included in the annual transmission interconnection study and shall send the list to the TSPs that own the projects.

(b) Within 20 Business Days of receipt of the list, each TSP that owns an identified transmission project shall send to ERCOT a PSS/E or PowerWorld formatted incremental change file to model the project in the current Regional Transmission Plan study cases.

(c) ERCOT shall post a study report detailing its findings on the MIS Secure Area within 20 Business Days of completion.

(2) After each Transmission Project and Information Tracking (TPIT) update ERCOT shall identify a list of transmission projects 100 kV or above that are expected to be in-service before the completion of the next annual transmission interconnection study and were not included in the previous transmission interconnection study, Regional Transmission Plan, an RPG project submission, or a GINR study pursuant to Section 5. ERCOT shall send the list to the TSPs that own the projects.

(a) Within 20 Business Days of receipt of the list, each TSP that owns an identified transmission project shall send to ERCOT a study report detailing the reliability impact analysis it conducted for the project. At a minimum the report shall identify the study base case(s), contingencies, and results.

(b) ERCOT shall review the TSP reports and provide comments to the TSP within 20 Business Days of receipt.

4.1 Introduction

Commented [CP2]: Please note PGRR117 also proposes revisions to this section.

(1) ERCOT employs both reliability criteria and economic criteria in evaluating the need for transmission system improvements. The economic criteria are included in Protocol Section 3.11.2, Planning Criteria. This Planning Guide provides the reliability criteria.

(2) The ERCOT System consists of those ~~generation~~~~Resource~~generation and Transmission Facilities (60 kV and higher voltages) that are controlled by individual Market Participants and that function as part of an integrated and coordinated system.

(3) To maintain reliable operation of the ERCOT System, it is necessary that all stakeholders observe and subscribe to certain minimum planning criteria. The criteria set forth in this Section 4.1 constitute the aforementioned minimum planning criteria. Tests outlined herein shall be performed to determine conformance to these minimum criteria; however, ERCOT recognizes that events more severe than those outlined in these criteria could cause grid separation and other tests may also be performed.

(4) The complexity and uncertainty inherent in the planning and operation of the ERCOT System make exhaustive studies impracticable; therefore, to gain maximum benefit from the limited number of tests performed, the selection of the specific tests and the frequency of their performance will be made solely upon the basis of the expected value of the reliability information obtainable from the test.

(5) ERCOT shall perform steady-state, short circuit, and dynamic analyses appropriate to ensure the reliability of the ERCOT System and identify appropriate solutions.

(6) Each Transmission Service Provider (TSP) will perform steady-state, short circuit, and dynamic analyses appropriate to ensure the reliability of its portion of the ERCOT System and implement appropriate solutions to meet the reliability performance criteria in this Section 4.1.

(7) The base cases created by the Steady-State Working Group (SSWG) and System Protection Working Group (SPWG) are available for use by Market Participants.

(8) If a TSP has its own planning criteria in addition to those defined in this Planning Guide, the TSP shall provide documentation of those criteria to ERCOT. ERCOT shall post the documentation on the Market Information System (MIS) Secure Area. The TSP shall notify ERCOT of any changes to their planning criteria and provide revised documentation within 30 days of such change.

[PGRR116: Replace paragraph (8) above with the following upon system implementation of NPRR1240:]

(8) If a TSP has its own planning criteria in addition to those defined in this Planning Guide, the TSP shall provide documentation of those criteria to ERCOT. ERCOT shall post the documentation on the ERCOT website. The TSP shall notify ERCOT of any changes to their planning criteria and provide revised documentation within 30 days of such change.

4.1.1.1 Planning Assumptions

Commented [CP3]: Please note PGRR115 also proposes revisions to this section.

(1) A contingency loss of an element includes the loss of an element with or without a single line-to-ground or three-phase fault.

(2) A common tower outage is the contingency loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater.

(3) Unavailability of a single generating unit includes an entire Combined Cycle Train, if no part of the train can operate with one of the units Off-Line as provided in the Resource Registration data.

(4) The contingency loss of a single generating unit shall include the loss of an entire Combined Cycle Train, if that is the expected consequence.

(5) The following assumptions may be applied to planning studies:

(a) Reasonable variations of load forecast, including forecasted load growth based on Substantiated Load;

(b) Reasonable variations of ~~generationunit~~generation commitment and dispatch applicable to transmission planning analyses on a case-by-case basis may include, but are not limited to, the following methods:

(i) Production cost model simulation, security constrained optimal power flow, or similar modeling tools that analyze the ERCOT System using hourly ~~generationResource~~generation dispatch assumptions;

(ii) Modeling of high levels of intermittent generation conditions; or

(iii) Modeling of low levels of or no intermittent generation conditions.

(6) Assumed Direct Current Tie (DC Tie) imports and exports will be curtailed as necessary to meet reliability criteria in planning studies.

(7) Manual System Adjustments shall not increase the amount of consequential load loss following a common tower outage, or the contingency loss of a single generating unit, transmission circuit, transformer, shunt device, FACTS device, or DC Tie Resource or DC Tie Load, with or without a single line-to-ground fault.

5 GENERATOR~~/ENERGY STORAGE SYSTEM~~ INTERCONNECTION OR MODIFICATION

5.2.1 Applicability

(1) The requirements in Section 5, Generator~~/Energy Storage System~~ Interconnection or Modification, apply to the following:

(a) Any Entity proposing to interconnect any generator~~ or energy storage system~~ with an aggregate nameplate capacity of one MW or greater, including but not limited to any Generation Resource or Energy Storage Resource (ESR), to the ERCOT System;

(b) Any Entity proposing to interconnect a Settlement Only Generator (SOG) to the ERCOT System; or

(c) Any Resource Entity seeking to modify a Generation Resource, ESR, or SOG that is connected to the ERCOT System by:

(i) Increasing the real power rating from that shown in the latest Resource Registration data by one MW or greater within a single year;

(ii) Changing the inverter, turbine, generator, battery modules, or power converter associated with a facility with an aggregate real power rating of ten MW or greater, unless the replacement is in-kind;

(iii) Modifying any control settings or equipment of Inverter-Based Resources (IBRs) that impact the dynamic response (such as voltage, frequency, and current injections) at the Point of Interconnection (POI) in a manner that is deemed to require further study in accordance with the process outlined in paragraph (5) of Section 5.5, Generator Commissioning and Continuing Operations;

(iv) Changing or adding a POI to a facility with an aggregate real power rating of ten MW or greater; or

(v) Increasing the aggregate nameplate capacity of a generator~~ or energy storage system~~ less than ten MW to ten MW or greater.

(2) For the purposes of Section 5, the term "generator" includes but is not limited to a Generation Resource, SOG, and ESR.

(3) For the purposes of determining the appropriate requirements in Section 5, a generator is considered a "large generator" if it currently has or is proposed to have an aggregate nameplate capacity of ten MW or greater. A generator is considered a "small generator" if it currently has or is proposed to have an aggregate nameplate capacity of less than ten MW.

(4) Notwithstanding paragraph (3), above, if a Resource Entity is proposing to increase the real power rating of an existing generator by one MW or greater but less than ten MW, that generator shall be considered a small generator for the purposes of the interconnection process described in Section 5.

(5) Notwithstanding paragraphs (3) and (4), above, if a Resource Entity is proposing to increase a generator's real power rating by ten MW or more, or is proposing to increase a generator's real power rating from less than ten MW to ten MW or more, that generator

shall be considered a large generator for the purposes of the interconnection process described in Section 5.

(6) For the purposes of determining the appropriate requirements in Section 5, ERCOT may require two or more separate generator interconnection requests to the same substation to follow the interconnection process applicable to the large generators, if, following the proposed change, those generators would have an aggregate nameplate capacity of ten MW or greater, and the projects are proposed by the same Entity or Affiliates.

(7) For a new or modified generator that has been designated as a Self-Limiting Facility or as a component of a Self-Limiting Facility, the categorization of the generator as a small generator or large generator pursuant to paragraphs (3) through (5) above shall be determined using the Self-Limiting Facility's established limit on the total MW Injection, or if applicable, the proposed increase in that value instead of the nameplate capacity of the Self-Limiting Facility.

5.3 Interconnection Study Procedures for Large Generators

(1) The provisions in this Section establish the procedures for conducting the Security Screening Study and Full Interconnection Study (FIS) for each new or modified large generator~~ or Energy Storage System (ESS)~~, as that term is defined by paragraph (3) of Section 5.2.1, Applicability.

5.3.1 Security Screening Study

(1) For each Generator~~/Energy Storage System~~ Interconnection or Modification (GIM) submitted for a large generator, ERCOT will conduct a steady-state Security Screening Study, including power-flow and transfer studies, based on the expected in-service year to identify potential generation dispatch limitations based on the site proposed by the Interconnecting Entity (IE).

(a) The Security Screening Study is a high-level review of the project and generally includes a number of initial assumptions from both ERCOT and the IE. In accordance with P.U.C. SUBST. R. 25.198, Initiating Transmission Service, ERCOT will establish the scope of the Security Screening Study that will include a determination of the need for a more in-depth Subsynchronous Resonance (SSR) study. The SSR vulnerability of all Generation Resources and ESRs applicable under Section 5, Generator~~/Energy Storage System~~ Interconnection or Modification, will be assessed pursuant to Protocol Section 3.22.1.2, Generation Resource or Energy Storage Resource Interconnection Assessment.

(b) At its sole discretion, ERCOT may waive the requirement for a Security Screening Study for a GIM.

(2) The results of the Security Screening Study will provide an indication of the level at which the proposed generator can expect to operate simultaneously with other known generators in the area before significant transmission additions or enhancements may be required. During the course of the Security Screening Study, ERCOT may consult with

the affected Transmission Service Provider(s) (TSP(s)), if needed, to identify the most efficient means of providing transmission service.

(3) During the Security Screening Study phase of the GIM process, and in accordance with the Protocols, all data, documents, and other information required by ERCOT from an IE related to a request for interconnection are considered Protected Information pursuant to Protocol Section 1.3.1.1, Items Considered Protected Information, to the extent that such information is not otherwise publicly available. Accordingly, ERCOT shall not publicly release any of the protected data, documents, or other information during the Security Screening Study phase except to TSPs. Information about interconnection requests in the Security Screening Study phase will only be released publicly in aggregated amounts.

(4) Upon completion of the Security Screening Study, ERCOT will present the IE with a preliminary report that will inform the IE about the suitability of the proposed Point of Interconnection (POI) for the proposed MW amount. This report does not imply any commitment by ERCOT or any TSP to recommend or construct transmission additions or enhancements. The report will also contain a description of the SSR assessment performed as part of the Security Screening Study and any conclusions resulting from the SSR assessment.

(5) Within 180 days of the date ERCOT notifies the IE of the Security Screening Study results, the IE must notify ERCOT, via the online Resource Integration and Ongoing Operations (RIOO) system, of its desire to pursue an FIS, otherwise ERCOT shall consider the GIM withdrawn by the IE. ERCOT will begin initiation and coordination of the FIS only after receiving this Notification and all required items from the IE for the FIS application to be approved. TSPs will receive a RIOO system automated email when ERCOT determines the FIS application is complete.

(6) After the expiration of the 180-day period, an IE must submit a new GIM for a Security Screening Study and must again pay the appropriate fee. The IE will also be required to submit any updates or changes in the project's data to ERCOT.

(7) For any interconnection request that proposes either a large generator that would be interconnected at distribution voltage or a qualifying modification to a large generator that is interconnected at distribution voltage, ERCOT will not initiate a Security Screening Study or propose any FIS kickoff meeting until the IE first provides written confirmation from the affected Distribution Service Provider (DSP) stating that the DSP has evaluated the proposed project, determined that the interconnection of the generator at distribution voltage is electrically feasible, and identified the necessary upgrades to accommodate the proposed interconnection. In conducting a Security Screening Study for such an interconnection request, ERCOT shall evaluate only the transmission-level impacts, if any, of the proposed generator, and the affected DSP shall provide ERCOT any information concerning the DSP's facilities or the proposed generator interconnection as may be requested by ERCOT for the purpose of completing the Security Screening Study.

5.3.2 Full Interconnection Study

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

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

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

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

(b) Complete Resource Registration data in the format prescribed by ERCOT with applicable information required for interconnection studies identified in the Resource Registration Glossary for the applicable Resource type. This information includes, among other things, the appropriate dynamic model for the proposed generator and results of the model quality tests and associated simulation files as described in paragraph (5)(c) of Section 6.2, Dynamics Model Development, subject to performance and usability verification by the lead TSP with approval from ERCOT through the FIS process. Dynamic model data shall be provided using the appropriate dynamic model template. Paragraph (5) of Section 6.2 and the Dynamics Working Group Procedure Manual contain more detail and IE dynamics data requirements. Data submitted for transient stability models shall be compatible with the current version of the planning and operations model software as described in the Dynamics Working Group Procedure Manual. If no compatible model exists, the IE shall work with a consultant or software vendor to develop and supply accurate/appropriate models along with other associated data. These models shall be incorporated into the standard model libraries of all software packages;

(c) An FIS Application Fee as described in the ERCOT Fee Schedule in the ERCOT Nodal Protocols, with the MW amount determined based on:

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

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

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

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

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

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

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

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

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

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

5.3.2.1 Proof of Site Control

(1) To establish proof of site control for the purposes of paragraph (3)(d) of Section 5.3.2, Full Interconnection Study, the IE must demonstrate through an affiliated company, through a trustee, or directly in its name that:

(a) The IE is the owner in fee simple of the real property to be utilized by the facilities for which any new generation ~~or energy storage~~ interconnection is sought;

(b) The IE holds a valid written leasehold interest in the real property to be utilized by the facilities for which new generation~~ or energy storage~~ interconnection is sought;

(c) The IE holds a valid written option to purchase or obtain a leasehold interest in the real property to be utilized by the facilities for which new generation ~~or energy storage~~ interconnection is sought; or

(d) The IE holds a duly executed written contract to purchase or obtain a leasehold interest in the real property to be utilized by the facilities for which new generation~~ or energy storage~~ interconnection is sought.

(2) The IE must notify ERCOT of any substantive change in status of the arrangement used to demonstrate site control.

(3) If the IE fails to maintain site control at any point before the date the generator~~ or ESS~~ is fully constructed, ERCOT will consider the interconnection request withdrawn as of the date of the loss of site control unless the applicant can show within 30 days that it has re-established site control or has established control of a new site that would not result in any material modification of any interconnection study requested under the current application.

5.3.2.3 Full Interconnection Study Description and Methodology

(1) The FIS consists of a series of distinct study elements. The specific elements that will be included in a particular FIS will be stated in the FIS agreement, and not all of the study elements specified below must be included if the IE and the TSP agree that one or more studies are unnecessary. The primary purpose of the FIS is to determine the most effective and efficient manner in which to achieve the proposed project while continuing to maintain the reliability of the ERCOT System by ensuring compliance with all North American Electric Reliability Corporation (NERC) Reliability Standards, Protocols, this Planning Guide and the Operating Guides. The scenarios and base cases being used for these studies to determine potential transmission limitations will be documented in the FIS study scope.

(2) Each proposed generator that requires a separate physical transmission interconnection will be treated as an individual study to be analyzed separately from all other such requests unless otherwise agreed by the IE and TSP(s) in the interconnection study agreement.

(3) The FIS process includes developing and analyzing various computer model simulations of the existing and proposed ERCOT generation/~~ESS/~~transmission system. The results from these simulations will be utilized by the TSP(s) to determine the impact of the proposed interconnection.

(4) The TSP(s) will examine normal transmission operations as well as potentially adverse, or contingency, conditions in order to identify and analyze the reliability and effectiveness of various interconnection design alternatives in alleviating or mitigating

any undesirable performance of the interconnection under a variety of operating conditions. The study should include analysis demonstrating the adequate reliability of any temporary interconnection configurations.

(5) In comparing interconnection alternatives, the TSP(s) will consider such information as interconnection cost and construction schedule, impact to short- and long-range reliability, operational flexibility, and compatibility with future transmission plans. The TSP(s) may consider interconnection alternatives not suggested by the IE.

(6) The TSP(s) may update the final FIS report to reflect changes to the ERCOT System (i.e., new Standard Generation Interconnection Agreements (SGIAs)) after the report is completed and before the SGIA is executed.

5.3.2.4.1 Steady-State Analysis

(1) The steady-state interconnection study base case shall be created from the most recently approved Steady State Working Group (SSWG) base case. TSP(s) or ERCOT may remove any future (currently nonexistent) facility from the steady-state interconnection study base case if either determines that the facility may significantly affect the interconnection study results and the facility has not already undergone appropriate review by the Regional Planning Group (RPG). In addition, ERCOT and TSP(s) may include other publicly disclosed projects in the steady-state interconnection study base case. ERCOT may request a list of the interconnection requests included in the FIS by the TSP(s). Modifications to the SSWG base case, necessary to evaluate the study results, shall be documented in the FIS but not to the extent that documenting the modifications would reveal Protected Information.

(2) The TSP(s) shall perform contingency analyses as required by the NERC Reliability Standards, Protocols, this Planning Guide and the Operating Guides and identify any additional facilities that may be necessary to ensure that expected system performance conforms to these standards. The study shall identify any system limitations that would prevent the generator from achieving full output.

(3) Loss-of-generation analyses shall assume that the lost generation will be replaced from all remaining Generation Resources and/or ESRs in proportion to their nominal capacity (i.e., inertial response and primary frequency response), and shall consider the generation limit of each Generation Resource and ESR.

(4) The lead TSP is responsible for completing an analysis of any contingency events or Outages that could result in a violation of the NERC Reliability Standards, Protocols, this Planning Guide and the Operating Guides, regardless of which TSP owns the facilities involved. The results of this analysis will be shared with TSP(s) that have facilities involved in planning criteria violations and those affected TSP(s) will be responsible for evaluating the validity of the anticipated violations.

Board Report

5.3.5 *ERCOT Quarterly Stability Assessment*

Commented [CP4]: Please note PGRR115 also proposes revisions to this section.

(1) ERCOT shall conduct a stability assessment every three months to assess the impact of planned large generators connecting to the ERCOT System. The assessment shall derive the conditions to be studied with consideration given to the results of the FIS stability studies for large generators, with planned Initial Synchronization in the period under study. ERCOT may study conditions other than those identified in the FIS stability studies.

(2) Large generators that are not included in the assessment as described in this Section as result of the IE failing to meet the prerequisites by the deadlines as listed in the table below will not be eligible for Initial Synchronization during that three-month period. The timeline for the quarterly stability assessment shall be in accordance with the following table:

Generator Initial Synchronization Date	Last Day for an IE to meet prerequisites as listed in paragraph (4) below	Completion of Quarterly Stability Assessment
Upcoming January, February, March	Prior August 1	End of October
Upcoming April, May, June	Prior November 1	End of January
Upcoming July, August, September	Prior February 1	End of April
Upcoming October, November, December	Prior May 1	End of July

(3) If the last day for an IE to meet prerequisites or if completion of the quarterly stability assessment as shown in the above table falls on a weekend or holiday, the deadline will extend to the next Business Day.

(4) The following prerequisites shall be satisfied prior to a large generator being included in the quarterly stability assessment:

(a) The generator has met the requirements of Section 6.9, Addition of Proposed Generation to the Planning Models.

(b) The IE has provided all generator data in accordance with the Resource Registration Glossary, Planning Model column, including but not limited to steady state, system protection and stability models.

(i) The IE shall submit the final dynamic data model at least 45 days prior to the quarterly stability assessment deadline described in paragraph (2) above. If ERCOT is unable to complete its review prior to the quarterly stability assessment deadline, ERCOT shall not include the Generation

Resource, ESR, or Settlement Only Generator (SOG) in that quarterly stability assessment.

(ii) Changes to the dynamic data model after the stability study is deemed complete may subject the Generation Resource, ESR, or SOG to modification of one or more FIS study elements as defined in paragraph (9) of Section 5.3.2.5, FIS Report and Follow-up. If ERCOT and the lead TSP(s) determine that modifications to one or more FIS study elements are required, then ERCOT shall not include the Generation Resource, ESR, or SOG in a quarterly stability assessment until the revised FIS has been completed in accordance with paragraph (4)(c)(i) below.

(iii) If an IE submitted a final dynamic data model at least 45 days prior to the quarterly stability assessment deadline but ERCOT determines that the Generation Resource, ESR, or SOG is ineligible to be included in a quarterly stability assessment pursuant to paragraphs (4)(b)(i) or (4)(b)(ii) above, ERCOT will send a notification to the IE.

(c) The following elements must be complete:

(i) Final FIS studies, which the TSP must have submitted via the online RIOO system at least 45 days prior to the quarterly stability assessment deadline;

(ii) Reactive Power Study; and

(iii) System improvements or mitigation plans that were identified in these studies as required to meet the operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents prior to synchronizing the generator.

(d) The data used in the studies identified in paragraph (4)(c) above is consistent with data submitted by the IE as required by Section 6.9.

(5) At any time following the inclusion of a large generator in a stability assessment, but before the Initial Synchronization of the generator, if ERCOT determines, in its sole discretion, that the generator no longer meets the prerequisites described in paragraph (4), or that an IE has made a change to the design of the generator that could have a material impact on ERCOT System stability, then ERCOT may refuse to allow Initial Synchronization of the generator, provided that ERCOT shall include the generator in the next quarterly stability assessment period that commences after identification of the material change or after the generator meets the prerequisites specified in paragraph (4), as applicable. If ERCOT determines, in its sole discretion, that the change to the design of the generator would not have a material impact on ERCOT System stability, then ERCOT may not refuse to allow Initial Synchronization of the generator due to this change.

(6) ERCOT shall post to the MIS Secure Area a report summarizing the results of the quarterly stability assessment within ten Business Days of completion.

6.1 Steady-State Model Development

(1) To adequately simulate steady-state system conditions, it is necessary to establish and maintain steady-state data and simulation-ready study cases in accordance with the ERCOT Steady State Working Group Procedure Manual. These case models, known as steady-state base cases, shall contain appropriate equipment characteristics and system data, and shall represent projected system conditions that provide a starting point for each required season and year.

(a) The Annual Planning Model base cases, which represent the annual peak load conditions, as prescribed in Protocol Section 3.10.2, Annual Planning Model, shall be developed annually, updated on a biannual basis, and may be updated as needed on an interim basis. Each Annual Planning Model base case, biannual updates, and off-cycle updates shall be posted on the Market Information System (MIS) Secure Area to ensure availability of the most accurate steady-state base cases.

(b) Additional steady-state base cases, such as seasonal base cases, shall also be developed annually, updated on a biannual basis, and may also be updated as needed on an interim basis. These derivative base cases, biannual updates, and off-cycle updates shall be posted on MIS Secure Area to ensure availability of the most accurate steady-state base cases.

(c) Off-cycle updates not associated with the biannual update shall be posted in a timely manner and include:

(i) Corrections to significant errors discovered in modeling or major changes in operation configuration that affect the steady-state base cases; or

(ii) A significant change in the scope or timing of a transmission project or the development of a new transmission project that impacts either of the next two summer base cases.

(d) Off-cycle updates that are posted as described in paragraphs (1)(a) through (c) above shall be in the form of a Power System Simulator for Engineering (PSS/E) formatted incremental change file.

(e) All steady-state base cases and incremental change files on the MIS Secure Area shall be available for use by Market Participants.

(f) The ERCOT Steady State Working Group Procedure Manual describes each base case that is required to be built. The schedule for posting all steady-state base cases shall be made available on the MIS Secure Area.

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(2) Transmission Service Providers (TSPs) and ERCOT shall develop the steady-state base cases. The steady-state base cases are derived from the Network Operations Model to ensure consistency of key characteristics, including Ratings, impedance and connectivity for Transmission Facilities that are common between the Network Operations Model and each steady-state base case. Minor differences between the models will occur for several reasons. For example:

(a) Additional detailed modeling may be added to the converted Network Operations Model for planning purposes.

(b) Future projects are added to the converted Network Operations Model that do not exist in the Network Operations Model past the model build date used to extract a snapshot from the Network Operations Model.

(3) Using the Network Model Management System (NMMS), ERCOT and TSPs shall create steady-state models that represent current and planned system conditions from the following data elements:

(a) Each TSP, or its Designated Agent, shall provide its respective transmission network steady-state model data, including load data.

(b) Each TSP, or its Designated Agent, shall not include the impact of energy sources connected to the Distribution System that are registered with ERCOT and required to provide telemetry including, but not limited to, Distribution Generation Resources (DGRs), Distribution Energy Storage Resources (DESRs), or Settlement Only Distribution Generators (SODGs) in its submitted Load data as negative loads or as embedded reductions in the submitted load forecast.

(c) Each TSP, or its Designated Agent, shall include the impact of energy sources connected to the Distribution System that are not registered with ERCOT in its submitted Load data. The methodology used shall be consistent across all TSPs and described in the ERCOT Steady State Working Group Procedure Manual.

(d) ERCOT shall utilize the latest available Resource Entity and Private Use Network model data submitted to ERCOT by the Resource Entity and the Private Use Network owners through the Resource Registration process for Resource Entities.

(e) ERCOT shall utilize proposed Generation Resource and Energy Storage Resource (ESR) model data provided by the Interconnecting Entity (IE) during the generation interconnection process in accordance with Section 5, Generator~~/Energy Storage System~~ Interconnection or Modification.

(f) ERCOT shall determine the operating state of Generation Resources and ESRs (MW, MVAr) using a security-constrained economic dispatch tool.

(g) ERCOT shall determine the import/export levels of asynchronous transmission interconnections based on historical data.

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6.2 Dynamics Model Development

Commented [CP5]: Please note PGRR121 also proposes revisions to this section.

(1) To adequately simulate dynamic and transient events in the ERCOT System, it is necessary to establish and maintain dynamics data and simulation-ready study cases representing the dynamic capability and frequency characteristics of machines and equipment connected to the ERCOT System.

(2) Dynamics data is the network data and mathematical models required in accordance with the Reliability and Operations Subcommittee (ROS)-approved Dynamics Working Group Procedure Manual for simulation of dynamic and transient events in the ERCOT System.

(3) For Resource Entities, dynamics data includes the data needed to represent the dynamic and transient response of Resource Entity-owned devices and/or Loads including but not limited to generating units, ~~Energy Storage Systems (ESSs),~~ plants, and other equipment when connected to the ERCOT System including the data for any privately owned transmission system or collection system used to connect the Resource to the ERCOT System.

(4) For Transmission Service Providers (TSPs), dynamics data needed to represent the dynamic and transient capability of TSP-owned devices including but not limited to Load shedding relays, protective relays, FACTS devices (e.g., SVC, STATCOMs), Direct Current Ties (DC Ties), variable-frequency transformers, automatically switched shunts, and transformers with automatic load tap changers.

[PGRR101: Replace paragraph (4) above with the following upon system implementation of NPRR1133:]

(4) For Transmission Service Providers (TSPs) and owners of Direct Current Ties (DC Ties), dynamics data includes the data needed to represent the dynamic and transient capability of dynamic devices including but not limited to Load shedding relays, protective relays, FACTS devices (e.g., SVC, STATCOMs), DC Ties, variable-frequency transformers, automatically switched shunts, and transformers with automatic load tap changers.

(5) The owner of a generator Facility or any dynamic device shall provide appropriate dynamics data to ERCOT, including the data for a planned Facility, in accordance with the Dynamics Working Group Procedure Manual. The dynamic data shall include the following:

(a) A model with parameters that accurately represent the dynamics of the device and that is compatible with the current version of the planning and operations model software as described in the Dynamics Working Group Procedure Manual. If a user written model is provided:

(i) A model manual containing a technical description of the model characteristics, including descriptions for all model parameters and variables, a list of which parameters are commonly tuned for site-specific settings, and a description of procedures and considerations for using the model in dynamic simulations, including steady state representation and limitations for model adequacy and usability in the planning and operations model software; and

(ii) The user-written model shall allow the user to determine the allocation of machine identifiers (bus numbers, bus names, machine IDs etc.) without restriction.

(b) Verification reports that support the model data based on documented field settings shall be provided as specified in the Dynamics Working Group Procedure Manual for Generation Resources, Energy Storage Resources (ESRs), and for Transmission Elements represented by a dynamic model. The reports shall demonstrate that the model parameters which are commonly tuned match site-specific settings implemented in the field. For new Generation Resources and ESRs, these reports shall be provided as required in paragraph (4) of Section 5.5, Generator Commissioning and Continuing Operations. For existing Generation Resources and ESRs, these reports shall be provided as required in paragraph (5) of Section 5.5. For Transmission Elements represented by a dynamic model, these reports shall be provided no later than two years following energization of new equipment and updated a minimum of every ten years.

(c) Results of model quality tests and associated simulation files that demonstrate acceptable performance of the models in the planning model and operations software as described in the Dynamics Working Group Procedure Manual. The Facility owner shall provide updated information whenever it provides a new or updated dynamic model to ERCOT representing a Generation Resource, ESR, or Transmission Element. These tests ensure the quality of the provided dynamic data and models for use in numerous system studies and consistency across planning and operations software platforms. Therefore, the Facility owner shall also assess sufficient sensitivities, including but not limited to Voltage Set Point at the Point of Interconnection (POI), real power output, and Reactive Power output to ensure acceptable model performance over the entire range of operating conditions. The Facility owner shall provide an explanation if model responses do not match.

(i) Facility owners shall include all site-specific dynamic models representing the Facility in the model quality tests. Facility owners can perform the tests in a simple test system without requiring ERCOT System information.

(ii) For Intermittent Renewable Resource (IRR) equipment aggregated together to form an IRR in accordance with paragraph (13) of Protocol Section 3.10.7.2, Modeling of Resources and Transmission Loads, the dynamic model shall represent the aggregated IRR.

(iii) Results for the following model quality tests shall be provided to demonstrate acceptable model performance. Additional details about each test, including the set up and description of desirable response, are included in the Dynamics Working Group Procedure Manual.

(A) Flat start test: A no-disturbance test shall be performed to demonstrate appropriate model initialization and the Facility's dynamic response under a no-disturbance condition.

(B) Small voltage disturbance test: A voltage step increase and decrease shall be applied to the POI to demonstrate the Facility's dynamic response.

(C) Large voltage disturbance test:

(1) For IRRs, ESRs, and inverter-based transmission equipment, the high and low voltage ride-through profiles as described in Nodal Operating Guide Section 2.9.1, Voltage Ride-Through Requirements for Intermittent Renewable Resources and Energy Storage Resources Connected to the ERCOT Transmission Grid, shall be applied to the POI to demonstrate the Facility's dynamic response.

(2) For Resources other than IRRs, ESRs, and inverter-based equipment, a fault shall be applied to the POI to demonstrate the Facility's dynamic response.

(D) Small frequency disturbance test: A frequency step increase and decrease shall be applied to the POI to demonstrate the Facility's dynamic response.

(E) System strength test: The model for IRRs and inverter-based Resources shall be tested under a few equivalent short circuit ratios, as described in the Dynamics Working Group Procedure Manual. This tests the robustness of the model to varying system conditions.

(d) Inverter-Based Resources (IBRs) shall provide results of the unit model validation to demonstrate that the PSCAD model, as described in the Dynamics Working Group Procedure Manual, accurately represents the dynamic responses of all inverter-based dynamic devices within the Facility. This validation is not intended to be site-specific; rather it is intended to be a hardware type test, where models representing different inverter hardware are benchmarked for accuracy. Validation results for a specific model of inverter can be submitted for multiple uses of that model of inverter.