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PROJECT NO. 54445

REVIEW OF PROTOCOLS ADOPTED BY THE INDEPENDENT ORGANIZATION	**§ § §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

NOTICE OF RECOMMENDED APPROVAL OF REVISION REQUESTS BY ERCOT BOARD OF DIRECTORS

Effective June 8, 2021, rules adopted by Electric Reliability Council of Texas, Inc. (ERCOT) under delegated authority from the Public Utility Commission of Texas (Commission) are subject to Commission oversight and review and may not take effect before receiving Commission approval.

At its meeting on April 8, 2025, the ERCOT Board of Directors (Board) recommended Commission approval of the following proposed revisions to the ERCOT rules (Revision Requests), (Nodal Protocol Revision Requests (NPRRs), Nodal Operating Guide Revision Requests (NOGRRs), Planning Guide Revision Requests (PGRRs), System Change Request (SCR); Settlement Metering Operating Guide Revision Request (SMOGRR), and Verifiable Cost Manual Revision Request (VCMRR)):

- NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs;
- NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater;
- NPRR1241, Firm Fuel Supply Service (FFSS) Availability and Hourly Standby Fee;
- NPRR1256, Settlement of MRA of ESRs;
- NPRR1268, RTC – Modification of Ancillary Service Demand Curves – URGENT;
- NPRR1269, RTC+B Three Parameters Policy Issues – URGENT;
- NPRR1270, Additional Revisions Required for Implementation of RTC – URGENT;
- NPRR1273, Appropriate Accounting for ESRs in PRC Calculation – URGENT;
- NOGRR274, Conform Nodal Operating Guide to Revisions Implemented for NPRR1217, Remove Verbal Dispatch Instruction (VDI) Requirement for Deployment and Recall of Load Resources and Emergency Response Service (ERS) Resources – URGENT;
- PGRR115, Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater;

- PGRR119, Stability Constraint Modeling Assumptions in the Regional Transmission Plan;
- SCR829, API for the NDCRC Application;
- SMOGRR028, Add Series Reactor Compensation Factors; and
- VCMRR042, SO2 and NOx Emission Index Prices Used in Verifiable Cost Calculations.

Included for Commission review are the Board Reports—each of which includes an ERCOT Market Impact Statement—and ERCOT Impact Analyses for these Revision Requests.

Also included for Commission review is the Alignment Nodal Operating Guide Revision Request form for NOGRR276, Alignment Changes for June 1, 2025 Nodal Operating Guide – NPRR1246 and NPRR1270. Alignment Revision Requests do not go through the stakeholder process, but still require Commission approval.

Dated: April 11, 2025

Respectfully submitted,

/s/ Brandt Rydell

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ATTORNEYS FOR ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

Board Report

NPRR Number	1190	NPRR Title	High Dispatch Limit Override Provision for Increased Load Serving Entity Costs
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None 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		
Nodal Protocol Sections Requiring Revision	3.8.1, Split Generation Resources 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) adds a provision for recovery of a demonstrable financial loss arising from a manual High Dispatch Limit (HDL) override to reduce real power output, in the case when that output is intended to meet Qualified Scheduling Entity (QSE) Load obligations.		
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		

Board Report

	(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	Section 6.6.3.6 currently allows for a QSE to file a timely dispute to recover a demonstrable financial loss stemming from a manual HDL override from the ERCOT Operator. In defining demonstrable financial losses, and in distinguishing these from opportunity costs which are not to be compensated, the current Protocol language allows for compensation for losses on Day-Ahead Market (DAM) obligations and on bilateral contracts that were affected by the HDL override. Non-Opt-In Entities (NOIEs) are bound by obligations to serve Load within their service territories, and generation supports this obligation in an arrangement akin to self-arrangement. When Security-Constrained Economic Dispatch (SCED)-dispatched generation would offset NOIE Load, and a manual HDL override reduces actual generation output, the NOIE incurs a concrete realized loss which is not an opportunity cost. The revised language would allow compensation for such a loss. The revision accounts for a compensable demonstrable financial loss when such loss is incurred by a NOIE due to ERCOT-instructed generation curtailment by an HDL override, and when revenue from that generation is regularly used to offset costs associated with serving that NOIE's Load. Section 3.8.1 describes obligations of the Master QSE of any Split Generation Resource. The revision provides that a Master QSE shall communicate manual High Dispatch Limit override instructions to all other QSEs that represent the Split Generation Resource. Such instructions shall be received by the Master QSE only, but such instructions allow for a dispute process for each QSE to recoup financial losses due to the HDL override. The revision would support all QSEs in meeting necessary timelines for the efficient application of Section 6.6.3.6.
PRS Decision	On 8/10/23, PRS voted unanimously to table NPRR1190 and refer the issue to WMS. All Market Segments participated in the vote. On 5/9/24, PRS voted to recommend approval of NPRR1190 as amended by the 3/26/24 Reliant comments. There were four opposing votes from the Consumer (4) (Residential, OPUC, City of Eastland, Occidental) Market Segment and eight abstentions from the Cooperative (PEC), Independent Generator (4) (Jupiter Power, NextEra Energy, ENGIE, EDF Renewables), Independent Power Marketer (IPM) (2) (Tenaska, SENA), and Investor Owned Utility (IOU) (Linebacker Power) Market Segments. All Market Segments participated in the vote.

Board Report

	On 6/13/24, PRS voted to endorse and forward to TAC the 5/9/24 PRS Report and 5/31/24 Impact Analysis for NPRR1190. There was one opposing vote from the Consumer (OPUC) Market Segment and two abstentions from the Consumer (Occidental) and IPM (DC Energy) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 8/10/23, one of the sponsors provided an overview of NPRR1190. Participants questioned whether alternative approaches to this issue might already exist, such as participation in the DAM, and requested additional review by WMS. On 5/9/24, participants noted the WMS endorsement of NPRR1190 as amended by the 3/26/24 Reliant comments. On 6/13/24, there was no discussion.
TAC Decision	On 6/24/24, TAC voted to recommend approval of NPRR1190 as recommended by PRS in the 6/13/24 PRS Report. There were six opposing votes from the Consumer (6) (Residential Consumer, OPUC, City of Eastland, City of Dallas, CMC Steel, Lyondell Chemical) Market Segment and one abstention from the Independent Retail Electric Provider (IREP) (Rhythm Ops) Market Segment. All Market Segments participated in the vote. On 10/30/24, TAC voted to table NPRR1190. There was one opposing vote from the Cooperative (LCRA) Market Segment. All Market Segments participated in the vote. On 2/27/25, TAC voted to recommend approval of NPRR1190 as recommended by TAC in the 6/24/24 TAC Report as amended by the 2/26/25 ERCOT comments. There were four opposing votes from the Consumer (Residential Consumer, OPUC, CMC Steel, Lyondell Chemical) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/24/24, TAC reviewed the items below. Opponents raised concerns that NPRR1190 incorrectly expands the opportunity for Entities to receive compensation for scheduled-but-not-provided energy under out-of-market ERCOT actions. Supporters noted the infrequent occurrence of the conditions covered by NPRR1190 and the language which prevents recovery of lost opportunity costs stemming from an HDL override. On 10/30/24, TAC reviewed the intention and procedural histories of NPRR649, Addressing Issues Surrounding High Dispatch Limit (HDL) Overrides, and NPRR1190. On 2/27/25, TAC reviewed the 1/30/25 Reliant comments, the 2/26/25 ERCOT comments, and the 2/26/25 Residential Consumer

	comments. Opponents restated their objection to NPRR1190 in principle.
Explanation of Opposing TAC Votes	**6/24/24 TAC Opposition Explanations:** **Consumer/Residential Consumer** – Residential Consumers voted "No" because this proposal is contrary to the nodal market design. Generators should be paid with high or low prices. The Board and Commission should reject proposals contrary to the fundamental principles of the market design or risk ever increasing costs. **Consumer/OPUC** – OPUC voted "No" because this proposal is contrary to the nodal market design. Generators should be paid with high or low prices. The Board and Commission should reject proposals contrary to the fundamental principles of the market design or risk ever increasing costs. **Consumer/City of Eastland** – City of Eastland agrees with the comments of the Residential Consumer and OPUC above. **Consumer/City of Dallas** – Explanation requested but not provided. **Consumer/CMC Steel** – Explanation requested but not provided. **Consumer/Lyondell Chemical** – Lyondell Chemical voted "No" because the NPRR would reward overscheduling of power that can't be delivered. A major reason the ERCOT market adopted nodal dispatch and pricing was to avoid paying for power that was scheduled but not delivered. Rejecting the NPRR would provide the proper incentives for dispatching existing units that could deliver power at that time and siting new generation in places where its power could be delivered at a future date. **2/27/25 TAC Opposition Explanations:** **Consumer/Residential Consumer** – Residential Consumers reiterated their opposition to NPRR1190 in principle, as detailed further in the 10/2/24 Joint Consumers comments and 2/26/25 Residential Consumer comments. **Consumer/OPUC** – OPUC reiterated their opposition to NPRR1190 in principle, as detailed further in the 10/2/24 Joint Consumers comments. **Consumer/CMC Steel** – CMC Steel reiterated their opposition to NPRR1190 in principle, as detailed further in the 10/2/24 Joint Consumers comments. **Consumer/Lyondell Chemical** – Lyondell Chemical reiterated their opposition to NPRR1190 in principle, as detailed further in the 10/2/24 Joint Consumers comments.

Board Report

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 (except the ERCOT Opinion – 2/27/25 TAC Report) [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 8/20/24, the ERCOT Board voted unanimously to table NPRR1190. On 10/10/24, the ERCOT Board voted unanimously to remand NPRR1190 to TAC. On 4/8/25, the ERCOT Board voted to recommend approval of NPRR1190 as recommended by TAC in the 2/27/25 TAC Report. There was one opposing vote.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1190 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1190.
ERCOT Opinion	ERCOT has no opinion on NPRR1190. NPRR1190 is primarily focused on a cost allocation issue; and determines the entities responsible for bearing the costs due to losses stemming from HDL overrides, an out of market action. NPRR1190 does not impact reliability or market design outcomes as ERCOT already has the authority to direct HDL overrides.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1190 and believes the market impact for this NPRR provides QSEs an additional opportunity to recover demonstrable financial losses stemming from an HDL override under certain conditions that previously were not allowed.

Sponsor	
Name	Alicia Loving, David Kee, Jose Gaytan, Russell Franklin, Ashley Cotton

Board Report

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Market Segment	Municipal

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
WMS 090723	Requested PRS continue to table NPRR1190 for further review by the Wholesale Market Working Group (WMWG)
Residential Consumer 111723	Proposed edits to narrow the scope of NPRR1190
Reliant 120423	Proposed edits to expand NPRR1190 to include QSEs rather than only NOIEs
ERCOT 030424	Responded to prior commenters and provided some context for how the current Section 6.6.3.6 language functions
Reliant 032624	Provided additional edits to add a QSE attestation rather than requiring them to submit contracts
ERCOT 032724	Provided additional clarifying edits to the 11/17/23 Residential Consumer comments
WMS 050224	Endorsed NPRR1190 as amended by the 3/26/24 Reliant comments
ERCOT 080824	Provided additional details on historical HDL overrides
ERCOT 091924	Provided a summary of NPRR1190 takeaways
Joint Consumers 100224	Opposed NPRR1190

Board Report

Reliant 013025	Proposed edits adding an annual cost threshold of $10 million which would trigger a review of both the operational and Settlement aspects of HDL override payments if that threshold was exceeded
ERCOT 022625	Proposed edits to the 1/30/25 Reliant comments lowering the threshold from $10 million to $3.5 million
Residential Consumer 022625	Reiterated opposition to NPRR1190 even with the reporting threshold proposed in the 1/30/25 Reliant comments

Market Rules Notes

Please note the baseline Protocol language in the following sections has been updated to reflect the incorporation of the following NPRRs into the Protocols:

- NPRR1185, HDL Override Payment Provisions for Verbal Dispatch Instructions (incorporated 11/1/23)
  - Section 6.6.3.6
- NPRR1186, Improvements Prior to the RTC+B Project for Better ESR State of Charge Awareness, Accounting, and Monitoring (unboxed 6/27/24)
  - Section 3.8.1
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)
  - Section 6.6.3.6

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

- NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
  - Section 6.6.3.6

Proposed Protocol Language Revision

3.8.1 Split Generation Resources

(1) When a generation meter is split, as provided for in Section 10.3.2.1, Generation Resource Meter Splitting, two or more independent Generation Resources must be created in the ERCOT Network Operations Model according to Section 3.10.7.2, Modeling of Resources and Transmission Loads, to function in all respects as Split Generation Resources in ERCOT System operation. A Combined Cycle Train may not be registered in ERCOT as a Split Generation Resource. A Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) may not be registered in ERCOT as a Split Generation Resource. An Energy Storage Resource (ESR) may not be registered in ERCOT as a Split Generation Resource.

(2) Each Qualified Scheduling Entity (QSE) representing a Split Generation Resource shall collect and shall submit to ERCOT the Resource Parameters defined under Section 3.7, Resource Parameters, for the Split Generation Resource it represents. The parameters provided must be consistent with the parameters submitted by each other QSE that represents a Split Generation Resource from the same Generation Resource. The parameters submitted for each Split Generation Resource for limits and ramp rates must be according to the capability of the Split Generation Resource represented by the QSE. Startup and shutdown times, time to change status and number of starts must be identical for all the Split Generation Resources from the same Generation Resource submitted by each QSE. ERCOT shall review data submitted by each QSE representing Split Generation Resources for consistency and notify each QSE of any errors.

(3) Each Split Generation Resource may be represented by a different QSE. The Resource Entities that own or control the Split Generation Resources from a single Generation Resource must designate a Master QSE. Each QSE representing a Split Generation Resource must comply in all respects to the requirements of a Generation Resource specified under these Protocols.

(4) The Master QSE shall:

(a) Serve as the Single Point of Contact for the Generation Resource, as required by Section 3.1.4.1, Single Point of Contact;

(b) Provide real-time telemetry for the total Generation Resource, as specified in Section 6.5.5.2, Operational Data Requirements;~~, and~~

(c) Receive Verbal Dispatch Instructions (VDIs) from ERCOT, as specified in Section 6.5.7.8, Dispatch Procedures; and

(d) Within five Business Days, notify all other QSEs that represent the Split Generation Resource when the Resource received an High Dispatch Limit (HDL) override instruction.

(5) Each QSE is responsible for representing its Split Generation Resource in its Current Operating Plan (COP). During the Reliability Unit Commitment (RUC) Study Periods, any conflict in the Resource Status of a Split Generation Resource in the COP is resolved according to the following:

(a) If a Split Generation Resource has a Resource Status of OUT for any hour in the COP, then any other QSEs' COP entries for their Split Generation Resources from the same Generation Resource are also considered unavailable for the hour;

(b) If the QSEs for all Split Generation Resources from the same Generation Resource have submitted a COP and at least one of the QSEs has an On-Line Resource Status in a given hour, then the status for all Split Generation Resources for the Generation Resource is considered to be On-Line for that hour, except if any of the QSEs has indicated in the COP a Resource Status of OUT.

(6) Each QSE representing a Split Generation Resource shall update its individual Resource Status appropriately.

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together.

[NPRR1007: Replace paragraph (7) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(7) Each QSE representing a Split Generation Resource may independently submit Energy Offer Curves, Ancillary Service Offers, and Three-Part Supply Offers. ERCOT shall treat each Split Generation Resource offer as a separate offer, except that all Split Generation Resources in a single Generation Resource must be committed or decommitted together.

(8) Each QSE submitting verifiable cost data to ERCOT shall coordinate among all owners of a single Generation Resource to provide individual Split Generation Resource data consistent with the total verifiable cost of the entire Generation Resource. ERCOT may compare the total verifiable costs with other similarly situated Generation Resources to determine the reasonability of the cost.

6.6.3.6 Real-Time High Dispatch Limit Override Energy Payment

Commented [CP1]: Please note NPRR1214 also proposes revisions to this section.

(1) If ERCOT directs a reduction in a Generation Resource's real power output by employing a manual High Dispatch Limit (HDL) override, or issues a Verbal Dispatch Instruction (VDI) to a Generation Resource to adjust its operation to produce the same effect, and the reduction causes the QSE to suffer a demonstrable financial loss, the QSE may be eligible for a Real-Time High Dispatch Limit Override Energy Payment, as calculated below~~, upon providing documented proof of that loss~~, upon providing documented proof of that loss. In order to qualify for this payment the QSE must:

(a) Have complied with ERCOT Dispatch Instructions to reduce real power output;

(b) Have either received a SCED Base Point equal to the Resource's HDL override value or received a SCED Base Point less than the Resource's output level at the time of the instruction but greater than or equal to the instructed operating level specified in the VDI, during the 15-minute Settlement Interval;

(c) Have incurred a demonstrable financial loss (excluding lost opportunity costs) caused by the HDL override ~~and~~ associated with one of the following:

(i) ~~v~~Variable cost components of DAM obligations;~~ or~~

(ii) QSEs representing Generation Resources in their portfolio with an HDL override for a Resource with a bilateral contract to sell energy at ~~only with energy sale provisions at the~~its Resource Node~~ of written bilateral contracts specific to the Generation Resource subject to the HDL override~~e~~E~~~~nergy purchase or sale provisions of bilateral contracts~~; ~~(as opposed to lost opportunity costs), in consequence of the HDL override or VDI that had an equivalent effect~~; or~~and~~

(iii) Incremental costs incurred by a ~~NOIE~~QSE in the Real-Time Market (RTM) to serve its Load ~~only~~ if the HDL override for a Resource in the same QSE portfolio as the Load, causes the QSE to be short energy compared to its Load for the intervals affected by the HDL override; and

(d) File a timely Settlement and billing dispute in accordance with Section 9.14, Settlement and Billing Dispute Process, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE;

(ii) The dollar amount and calculation of the financial loss by Settlement Interval;

(iii) An explanation of the nature of the loss and how it was attributable to the HDL override or equivalent VDI issued by ERCOT; and

(iv) Sufficient documentation to support the QSE's calculation of the amount of the financial loss.

(2) Notwithstanding the attestation requirement described in paragraph (1)(d) above, for QSEs filing a demonstrable financial loss per paragraph (1)(c)(iii) above, the attestation must also state that the Resource with the HDL override was serving the Load in the same QSE portfolio as the Resource, at the time the HDL override was issued.

(3) If the total Settlement amount of High Dispatch Limit Override Energy Payment exceeds $3.5~~10~~ million in a calendar year, ERCOT will report to the Technical Advisory Committee (TAC) the causes of the payments and provide recommendations on how to reduce the costs both operationally and based on the eligible demonstrable financial loss criteria in paragraph (1)(c) above.

(4) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 business days of ERCOT's request. ERCOT will provide Notice of its acceptance or rejection of the claim for the High Dispatch Limit Override Energy Payment within 15 Business Days of the updated submission.

(5~~43~~) The Energy Offer Curve used to calculate the Real-Time High Dispatch Limit Override Energy Payment will be the most recent valid Energy Offer Curve received by ERCOT that was effective for the disputed interval(s) when the HDL override or equivalent VDI was issued. If no curve exists for the interval being disputed, ERCOT will use the most recent valid Energy Offer Curve received before the HDL override or equivalent VDI was issued for an interval prior to the disputed interval(s).

The payment shall be calculated as follows:

$$\mathbf{HDLOEAMT}_{q,\,r,\,p,\,i} = \mathbf{(-1) * Min\ \{HDLOAL}_{q,\,r,\,p,\,i}\mathbf{,\ Max(0,\ ((RTSPP}_{p,\,i}\mathbf{ - RTRSVPOR}_{i}\mathbf{ - RTRDP}_{i}\mathbf{ - RTEOCOST}_{q,\,r,\,i}\mathbf{)\ *\ HDLOQTY}_{q,\,r,\,p,\,i}\mathbf{))\}}$$

Where:

$$\text{HDLOQTY}_{q,\,r,\,p,\,i} = \text{Max}(0,\ (\tfrac{1}{4}\ (\text{HDLOBRKP}_{q,\,r,\,p,\,i} - \text{AVGHDL}_{q,\,r,\,p,\,i})))$$

$$\text{HDLOBRKP}_{q,\,r,\,p,\,i} = \text{Min}(\text{AVGHASL}_{q,\,r,\,p,\,i},\ \text{HDLOBRKPCP}_{q,\,r,\,p,\,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
HDLOAL $_{q,\,r,\,p,\,i}$	$	*High Dispatch Limit override attested losses*—The financial loss to the QSE due to the HDL override as attested by the QSE in accordance with paragraph (1)(d) above.
HDLOEAMT $_{q,\,r,\,p,\,i}$	$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
HDLOBRKP $_{q,\,r,\,p,\,i}$	MW	*High Dispatch Limit override break point per QSE per Resource*—The point on the Energy Offer Curve corresponding to the lesser of the AVGHASL or the interception between the RTSPP of the Generation Resource *r* represented by QSE *q* minus the Real-Time Reserve Price for On-Line Reserves and the Real-Time On-Line Reliability Deployment Price and the Energy Offer Curve of Generation Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
AVGHDL $_{q,\,r,\,p,\,i}$	MW	*Average High Dispatch Limit per QSE per Settlement Point per Resource*—The time-weighted average of all 4-second HDL values calculated by the Resource Limit Calculator, subject to the maximum of the manual HDL override or equivalent VDI and the telemetered output or consumption, for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
AVGHASL $_{q,\,r,\,p,\,i}$	MW	*Average High Ancillary Service Limit per QSE per Settlement Point per Resource*—The time-weighted average High Ancillary Service Limit (HASL) calculated every four seconds by the Resource Limit Calculator for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. In the case of a VDI that is equivalent to an HDL override, this value is set equal to the HASL of Generation Resource or Controllable Load Resource *r* at the time that the VDI is issued to the QSE.

Board Report

Variable	Unit	Definition
HDLOBRKPCP $_{q,\,r,\,p,\,i}$	MW	*High Dispatch Limit override break point at clearing price per QSE per Resource*—The MW value on the Energy Offer Curve corresponding to the Real-Time Settlement Point Price of Generation Resource *r* represented by QSE *q* at Settlement Point *p* minus the Real-Time Reserve Price for On-Line Reserves and the Real-Time On-Line Reliability Deployment Price. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTEOCOST $_{q,\,r,\,i}$	$/MWh	Real-Time Energy Offer Curve Cost Cap—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
HDLOQTY $_{q,\,r,\,p,\,i}$	MWh	*High Dispatch Limit override quantity per QSE per Generation Resource*—The difference between the HDLOBRKP and the AVGHDL due to an ERCOT-issued HDL override or equivalent VDI for Generation Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTSPP $_{p,\,i}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
RTRSVPOR $_{i}$	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
RTRDP $_{i}$	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

(65~~4~~) The total compensation to each QSE for an HDL override for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{HDLOEAMTQSETOT}_{\,q,\,i} = \sum_{r} \sum_{p} \mathbf{HDLOEAMT}_{\,q,\,r,\,p,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
HDLOEAMT $_{q,\,r,\,p,\,i}$	$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
HDLOEAMTQSETOT $_{q,\,i}$	$	*High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for HDL overrides for this QSE for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource.

Variable	Unit	Definition
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

[NPRR1010 and NPRR1246: Replace Section 6.6.3.6 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.6.3.6 Real-Time High Dispatch Limit Override Energy Payment

(1) If ERCOT directs a Generation Resource or Energy Storage Resource (ESR) to reduce real power output by employing a manual High Dispatch Limit (HDL) override, or issues a Verbal Dispatch Instruction (VDI) to a Generation Resource or ESR to adjust its operation to produce the same effect, and the reduction causes the QSE to suffer a demonstrable financial loss, the QSE may be eligible for a Real-Time High Dispatch Limit Override Energy Payment, as calculated below~~, upon providing documented proof of that loss~~, upon providing documented proof of that loss. In order to qualify for this payment the QSE must:

(a) Have complied with ERCOT Dispatch Instructions to reduce real power output;

(b) Have either received a SCED Base Point equal to the Resource’s HDL override value or received a SCED Base Point less than the Resource’s output level at the time of the instruction but greater than or equal to the instructed operating level specified in the VDI, during the 15-minute Settlement Interval;

(c) Have incurred a demonstrable financial loss (excluding lost opportunity costs) caused by the HDL override ~~and~~ associated with one of the following:

(i) ~~v~~ Variable cost components of DAM obligations;

(ii) QSEs representing only Generation Resources ~~only~~in their portfolio with an HDL override for a Resource with a ~~energy sale provisions at the Resource Node of written~~ bilateral contract~~s~~ to sell energy at its Resource Node~~specific to the Generation Resource subject to the HDL override~~ ~~or e~~ ~~Energy purchase or sale provisions of bilateral contracts~~; ~~(as opposed to lost opportunity costs), in consequence of the HDL override or VDI that had an equivalent effect~~; ~~and~~or

(iii) Incremental costs incurred by a ~~NOIE~~QSE in the Real-Time Market (RTM) to serve its Load ~~only~~ if the HDL override for a Resource in the same QSE portfolio as the Load, causes the QSE to be short energy compared to its Load; and

(d) File a timely Settlement and billing dispute in accordance with Section 9.14, Settlement and Billing Dispute Process, including the following items:

(i) An attestation signed by an officer or executive with authority to bind the QSE;

(ii) The dollar amount and calculation of the financial loss by Settlement Interval;

(iii) An explanation of the nature of the loss and how it was attributable to the HDL override or equivalent VDI issued by ERCOT; and

(iv) Sufficient documentation to support the QSE's calculation of the amount of the financial loss.

(2) Notwithstanding the attestation requirement described in paragraph (1)(d) above, for QSEs filing a demonstrable financial loss per paragraph (1)(c)(iii) above, the attestation must also state that the Resource with the HDL override was serving the Load in the same QSE portfolio as the Resource, at the time the HDL override was issued.

(3) If the total Settlement amount of High Dispatch Limit Override Energy Payments exceeds $3.5~~10~~ million in a calendar year, ERCOT will report to the Technical Advisory Committee (TAC) the causes of the payments and provide recommendations on how to reduce the costs both operationally and based on the eligible demonstrable financial loss criteria in paragraph (1)(c) above.

(4~~3~~) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within 15 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT's request. ERCOT will provide Notice of its acceptance or rejection of the claim for the High Dispatch Limit Override Energy Payment within 15 Business Days of the updated submission.

(5~~43~~) The Energy Offer Curve or Energy Bid/Offer Curve used to calculate the Real-Time High Dispatch Limit Override Energy Payment will be the most recent valid Energy Offer Curve or Energy Bid/Offer Curve received by ERCOT that was effective for the disputed interval(s) when the HDL override or equivalent VDI was issued. If no curve exists for the interval being disputed, ERCOT will use the most recent valid Energy Offer Curve or Energy Bid/Offer Curve received before the HDL override or equivalent VDI was issued for an interval prior to the disputed interval(s).

(6~~54~~) The amount recoverable under this section shall be offset by any Ancillary Service Imbalance revenues received by the QSE that the QSE would not have earned had ERCOT not issued an HDL override.

The payment shall be calculated as follows:

$$\mathbf{HDLOEAMT}_{q,r,p,i} = \mathbf{(-1) * Min \{HDLOAL}_{q,r,p,i}\mathbf{, Max(0, ((RTSPP}_{p,i}\mathbf{ - RTRDP}_i\mathbf{ - RTEOCOST}_{q,r,i}\mathbf{) * HDLOQTY}_{q,r,p,i}\mathbf{))\}}$$

Where:

$$\text{HDLOQTY}_{q,r,p,i} = \text{Max}(0, (\tfrac{1}{4} (\text{HDLOBRKP}_{q,r,p,i} - \text{AVGHDL}_{q,r,p,i})))$$

$$\text{HDLOBRKP}_{q,r,p,i} = \text{Min}(\text{AVGHSL}_{q,r,p,i}, \text{HDLOBRKPCP}_{q,r,p,i})$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{HDLOAL}_{q,r,p,i}$	$	*High Dispatch Limit override attested losses*—The financial loss to the Resource *r* represented by QSE *q* due to the HDL override as attested by the QSE in accordance with paragraph (1)(d) above. For a combined cycle Resource, *r* is a Combined Cycle Train.
$\text{HDLOEAMT}_{q,r,p,i}$	$	*High Dispatch Limit override energy amount per QSE per Generation Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
$\text{HDLOBRKP}_{q,r,p,i}$	MW	*High Dispatch Limit override break point per QSE per Resource*—The point on the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the lesser of the AVGHSL or the interception between the RTSPP of the Resource *r* represented by QSE *q* minus the Real-Time Reliability Deployment Price for Energy and the Energy Offer Curve Cost Cap of Resource *r* represented by QSE *q*, for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
$\text{AVGHDL}_{q,r,p,i}$	MW	*Average High Dispatch Limit per QSE per Settlement Point per Resource*—The time-weighted average of all 4-second HDL values calculated by the Resource Limit Calculator, subject to the maximum of the manual HDL override or equivalent VDI and the telemetered output, for the Generation Resource or ESR *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
$\text{AVGHSL}_{q,r,p,i}$	MW	*Average High Sustained Limit per QSE per Settlement Point per Resource*—The time-weighted average High Sustained Limit (HSL) for the Generation Resource or ESR *r* represented by QSE *q* at Settlement Point *p* within the 15-minute Settlement Interval *i*. For a Combined Cycle Train, the Resource *r* is a Combined Cycle Train. In the case of a VDI that is equivalent to an HDL override, this value is set equal to the HSL of Generation Resource, or ESR *r* at the time that the VDI is issued to the QSE.
$\text{HDLOBRKPCP}_{q,r,p,i}$	MW	*High Dispatch Limit override break point at clearing price per QSE per Resource*—The MW value on the Energy Offer Curve or Energy Bid/Offer Curve corresponding to the Real-Time Settlement Point Price of Resource *r* represented by QSE *q* at Settlement Point *p* minus the Real-Time Reliability Deployment Price for Energy. For a combined cycle Resource, *r* is a Combined Cycle Train.

RTEOCOST $_{q,r,i}$	\$/MWh	*Real-Time Energy Offer Curve Cost Cap*—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the Low Sustained Limit (LSL) for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
HDLOQTY $_{q,r,p,i}$	MWh	*High Dispatch Limit override quantity per QSE per Generation Resource*—The difference between the HDLOBRKP and the AVGHDL due to an ERCOT-issued HDL override or equivalent VDI for Resource *r* represented by QSE *q* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
RTSPP $_{p,i}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
RTRDP $_{i}$	\$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
q	none	A QSE.
r	none	A Generation Resource or ESR.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

(7~~65~~) The total compensation to each QSE for an HDL override for the 15-minute Settlement Interval is calculated as follows:

$$\textbf{HDLOEAMTQSETOT}_{q,i} = \sum_{r} \sum_{p} \textbf{HDLOEAMT}_{q,r,p,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
HDLOEAMT $_{q,r,p,i}$	\$	*High Dispatch Limit override energy amount per QSE per Resource*—The payment to QSE *q* for an ERCOT-issued HDL override or equivalent VDI for Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.
HDLOEAMTQSETOT $_{q,i}$	\$	*High Dispatch Limit override energy amount QSE total per QSE*—The total of the energy payments to QSE *q* as compensation for HDL overrides for this QSE for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource or ESR.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

ERCOT Impact Analysis Report

NPRR Number	1190	NPRR Title	High Dispatch Limit Override Provision for Increased Load Serving Entity Costs
Impact Analysis Date	May 31, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1234	NPRR Title	Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
Date of Decision		April 8, 2025	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Between $600K and $800K; Between $180K and $220K (Annual Recurring O&M) Project Duration: 12 to 18 months	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Priority – 2026; Rank – 4730	
Requested Resolution		Normal	
Nodal Protocol Sections Requiring Revision		2.1, Definitions 2.2, Acronyms and Abbreviations 3.1.1, Role of ERCOT 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests 3.3.2, Types of Work Requiring ERCOT Approval 3.10.7.2, Modeling of Resources and Transmission Loads 3.10.7.5, Telemetry Requirements 3.10.7.5.1, Continuous Telemetry of the Status of Breakers and Switches 3.15, Voltage Support 3.15.3, Generation Resource Requirements Related to Voltage Support 3.22, Subsynchronous Resonance 3.22.1, Subsynchronous Resonance Vulnerability Assessment 3.22.1.1, Existing Generation Resource Assessment 3.22.1.2, Generation Resource or Energy Storage Resource Interconnection Assessment 3.22.1.3, Transmission Project Assessment 3.22.1.4, Large Load Interconnection Assessment (new) 3.22.1.4, Annual SSR Review 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria 3.22.3, Subsynchronous Resonance Monitoring 16.5, Registration of a Resource Entity ERCOT Fee Schedule	

Board Report

Related Documents Requiring Revision/Related Revision Requests	Planning Guide Revision Request (PGRR) 115, Related to NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
Revision Description	This Nodal Protocol Revision Request (NPRR) and the related PGRR115 establish interconnection and modeling requirements for "Large Loads"—defined in this NPRR to refer to one or more Facilities at a single site with an aggregate peak power Demand of 75 MW or more. ERCOT proposes these requirements based upon its experience with the interim large Load interconnection process implemented on March 25, 2022, analysis of operational events, and the discussion of various issues concerning Large Loads explored by the Large Flexible Load Task Force (LFLTF). Additionally, this NPRR facilitates the addition of a new study process for Large Loads seeking to interconnect to the ERCOT system. This process is described in the accompanying PGRR115. This NPRR also adds a requirement that any Resource Entity that adds 20 MW or more of Load at any site with an existing Generation Resource shall submit a new Reactive Power study. The study must demonstrate the continued compliance of the Generation Resource with Voltage Support Service (VSS) requirements. This NPRR also establishes specific Subsynchronous Oscillation (SSO) requirements for Large Loads and revises and supplements SSO-related definitions, in addition to clarifying existing SSO requirements. Furthermore, although the primary focus of this NPRR is Loads that are 75 MW or larger, this NPRR also establishes new standards for the identification and classification of a site with an aggregate peak Demand of 25 MW or more at a common substation in ERCOT Network Operations Model. Such information will provide ERCOT visibility of the locations of these Loads for operational and planning purposes. Finally, this NPRR adds a fee for Large Load Interconnection Study (LLIS) Requests to the ERCOT Fee Schedule. These revisions address some planning, modeling, and operational concerns that have been identified thus far relating to Large Loads. But some issues identified by the LFLTF remain unresolved. Accordingly, and as the impacts of Large Loads on the grid become better understood, additional Revision Requests may be necessary to address additional risks to reliability.
Reason for Revision	☒ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience

Board Report

	☐ 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	The ERCOT System is experiencing an unprecedented increase in the number of sites with Loads that are each sizeable enough to potentially affect the reliable operation of the Texas power grid. For example, since January 1, 2022, a total of 4,479 MW of Large Loads (those equaling 75 MW or more at a site) have received ERCOT approval to energize in. That amount is several times larger the Demand of the City of Lubbock, which underwent a significantly more lengthy and involved process to interconnect to the ERCOT system. This amount also does not include other Large Loads seeking to interconnect to the ERCOT System under slower time frames. Additionally, as of May 1, 2024, ERCOT has received an additional 19,754 MW of proposed projects requesting energization on or before December 31, 2025, of which 8,952 MW has already received ERCOT approval of interconnection studies performed by the TSP. For perspective, 19,754 MW of additional Load represents almost one-quarter of the recent ERCOT record peak Demand of 85,508 MW set on August 10, 2023. Moreover, due in part to ERCOT's limited visibility regarding Customers' electrical Facilities and their operations, ERCOT is observing greater error in its Load forecasts since this rapid increase in Large Load interconnections began. Such error is particularly problematic during extreme or unusual Operating Days when having an accurate forecast is most critical for reliability. In this NPRR, ERCOT proposes in part to identify Loads in the Network Operations Model with an aggregate peak Demand of 25 MW or more at a site behind one or more common Points of Interconnection (POIs) or Service Delivery Points to provide certain information for ERCOT visibility. This improved Load identification will aid ERCOT in addressing a growing reliability concern around

	the predictability of forecasted customer Demand. ERCOT will coordinate with Market Participants to identify the delivery point for customers' Loads that are 25 MW and larger. To address the risks to reliability discussed above, this NPRR and the accompanying PGRR115 propose practicable solutions. These Revision Requests are informed by, among other things, stakeholders' contributions in LFLTF and the interim ERCOT process established to study Large Loads seeking to interconnect sooner than the two-year time frame contemplated in the traditional planning process. ERCOT appreciates stakeholders' engagement thus far and looks forward to their further comments.
PRS Decision	On 6/13/24, PRS voted unanimously to table NPRR1234 and refer the issue to ROS. All Market Segments participated in the vote. On 2/12/25, PRS voted to recommend approval of NPRR1234 as amended by the 1/24/25 ERCOT comments. There was one opposing vote from the Consumer (Occidental) Market Segment and one abstention from the Independent Power Marketer (IPM) (Tenaska) Market Segment. All Market Segments participated in the vote. On 3/12/25, PRS voted to endorse and forward to TAC the 2/12/25 PRS Report and 5/28/24 Impact Analysis for NPRR1234 with a recommended priority of 2026 and rank of 4730. There was one opposing vote from the Consumer (Occidental) Market Segment and one abstention from the Independent Generator (Calpine) Market Segment. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/13/24, the ERCOT staff provided an overview of NPRR1234, noting some of the differences in scope from the original NPRR1191. Participants noted ongoing discussions at the LFLTF and requested additional review at ROS alongside PGRR115, particularly the modeling requirements for Loads larger than 25 MW. On 2/12/25, participants reviewed the 1/24/25 ERCOT comments and 2/11/25 Occidental Chemical comments. Some supporters questioned the level of the Large Load Interconnection Study (LLIS) fee, noting the higher fee proposed within NPRR1202, Refundable Deposits for Large Load Interconnection Studies, and requested ERCOT increase this fee within NPRR1234. On 3/12/25, participants reiterated support for NPRR1234 but requested ERCOT continue to their analysis of the LLIS fee amount for a possible increase. ERCOT Staff noted the potential for a separate Revision Request addressing fee modifications for both loads and generators.

Board Report

TAC Decision	On 3/26/25, TAC voted unanimously to recommend approval of NPRR1234 as recommended by PRS in the 3/12/25 PRS Report as amended by the 3/25/25 ERCOT comments as revised by TAC. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, TAC reviewed the items below, and discussed desktop edits to extend the compliance timelines in Section 3.10.7.2 in the spirit of similar extensions provided in PGRR115. ERCOT Staff reiterated the need for NPRR1234 and PGRR115 as an important first step in formalization of the interconnection process for Large Loads and committed to working with stakeholders on subsequent Revision Request(s) to clarify/improve the process.
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 4/8/25, the ERCOT Board voted unanimously to recommend approval of NPRR1234 as recommended by TAC in the 3/26/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1234 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1234.
ERCOT Opinion	ERCOT supports approval of NPRR1234.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1234 and believes the market impact for NPRR1234, along with PGRR115, provides necessary structure and clarification to the interconnection requirements for Large Loads.

Sponsor

Board Report

Name	Bill Blevins
E-mail Address	Bill.Blevins@ercot.com
Company	ERCOT
Phone Number	512-248-6691
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Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	cory.phillips@ercot.com
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Comments Received	
Comment Author	**Comment Summary**
ERCOT Steel Mills 062624	Proposed edits classifying "end-use industry classification" of Load Points as Protected Information
ROS 071124	Requested PRS continue to table NPRR1234 for further review by the Network Data Support Working Group (NDSWG)
ERCOT 081224	Responded to the 6/26/24 ERCOT Steel Mills comments
Oncor 081524	Proposed several clarifying edits within Section 3, Management Activities for the ERCOT System
ERCOT Steel Mills 091824	Responded to the 8/12/24 ERCOT comments and provided additional edits to the 6/26/24 ERCOT Steel Mills comments
ERCOT 111124	Proposes additional new and modified definitions in Section 2.1
CenterPoint 121224	Proposed additional edits to definitions on top of the 11/11/24 ERCOT comments
ERCOT 121624	Responded to issues raised by Oncor and provided additional edits to the 8/15/24 Oncor comments
ERCOT 012425	Proposed additional clarifying edits to the 12/16/24 ERCOT comments based on discussions with the Planning Working Group (PLWG)

Board Report

ROS 020625	Endorsed NPRR1234 as amended by the 1/24/25 ERCOT comments
Occidental Chemical 021125	Proposed edits to the 1/24/25 ERCOT comments to clarify that a Generation Resource's or Energy Storage Resource's (ESR's) reactive capability is not required to compensate for any VAr consumption by the co-located load
ERCOT 032525	Proposed additional revisions to account for ESRs in alignment with recently-approved NPRR1246.

Market Rules Notes

Please note the baseline Protocol language in the following sections(s) has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions (unboxed 9/27/24)
    - Section 16.5
- NPRR1233, Modification of Weatherization Inspection Fees on the ERCOT Fee Schedule (incorporated 10/1/24)
    - ERCOT Fee Schedule
- NPRR1240, Access to Transmission Planning Information (incorporated 2/1/25)
    - Section 3.15
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)
    - Section 3.1.1
    - Section 3.1.5.11
    - Section 3.10.7.2
    - Section 3.22.1.2
    - Section 3.22.1.3
    - Section 3.22.1.4
    - Section 3.22.2
    - Section 3.22.3
    - Section 16.5

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

- NPRR1202, Refundable Deposits for Large Load Interconnection Studies
    - Section 2.1
    - ERCOT Fee Schedule
- NPRR1265, Unregistered Distributed Generator
    - Section 16.5
- NPRR1272, Voltage Support at Private Use Networks

- Section 3.15

Please note administrative changes have been made below and authored as "ERCOT Market Rules".

Proposed Protocol Language Revision

2.1 DEFINITIONS

Commented [CP1]: Please note NPRR1202 also proposes revisions to this section.

Initial Energization

The first time a Generation Resource ~~or~~, Settlement Only Generator (SOG), or Large Load facility's equipment connects to the ERCOT System during commissioning of the new or modified Generation Resource, SOG, or Large Load.

[NPRR995: Replace the above definition "Initial Energization" with the following upon system implementation:]

Initial Energization

The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), ~~or~~ Settlement Only Generator (SOG), or Large Load facility's equipment connects to the ERCOT System during commissioning of the new or modified Generation Resource, ESR, SOESS, SOG, or Large Load.

Initial Synchronization

The first time a Generation Resource or Settlement Only Generator (SOG) facility's new equipment injects power to the ERCOT System during commissioning of the new or modified Generation Resource or SOG.

[NPRR995: Replace the above definition "Initial Synchronization" with the following upon system implementation:]

Initial Synchronization

The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) facility's new equipment injects power to the ERCOT System during commissioning of the new or modified Generation Resource, ESR, SOESS, or SOG.

Large Load

One or more Facilities at a single site with an aggregate peak Demand greater than or equal to 75 MW behind one or more common Points of Interconnection (POIs) or Service Delivery Points.

Large Load Interconnection Study (LLIS)

The set of studies conducted by a Transmission Service Provider (TSP) for the purpose of identifying any electric system improvements or enhancements required to reliably interconnect a Customer with a Large Load meeting the requirements of Planning Guide Section 9.2.2, Applicability. These studies may include steady-state studies, system protection (short-circuit) studies, dynamic and transient stability studies, facility studies, and sub-synchronous oscillation studies.

Initial Energization

The first time a Generation Resource ~~or~~, Settlement Only Generator (SOG), or Large Load facility's equipment connects to the ERCOT System during commissioning.

[NPRR995: Replace the above definition "Initial Energization" with the following upon system implementation:]

Initial Energization

The first time a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), ~~or~~ Settlement Only Generator (SOG) facility's equipment connects to the ERCOT System during commissioning.

Interconnecting Large Load Entity (ILLE)

Any Entity upon whose behalf a Transmission Service Provider, Resource Entity, or Interconnecting Entity has submitted a request to interconnect a Large Load to the ERCOT system.

Subsynchronous Oscillation (SSO)

Coincident oscillation occurring between two or more Transmission Elements, ~~or~~ Generation Resources, Energy Storage Resources (ESRs), or Load at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz).

Induction Generator Effect (IGE)

An electrical phenomenon in which a resonance involving a Generation Resource or Load and a series compensated transmission system results in electrical self-excitation of the Generation Resource or Load at a subsynchronous frequency.

Subsynchronous Control Interaction (SSCI)

The interaction between a series capacitor compensated transmission system and the control system of Generation Resources, ESRs, or Load.

Board Report

Subsynchronous Ferroresonance (SSFR)

Coincident oscillation occurring between a transformer and a series capacitor-compensated transmission system at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz).

Subsynchronous Resonance (SSR)

Coincident oscillation occurring between Generation Resources or Energy Storage Resources (ESRs) and a series capacitor compensated transmission system at a natural harmonic frequency lower than the normal operating frequency of the ERCOT System (60 Hz), including the following types of interactions:

Torque Amplification

An interaction between one or more Generation Resources and a series compensated transmission system in which the response results in higher transient torque during or after disturbances than would otherwise occur.

Torsional Interaction

Torsional Interaction is the interplay between the mechanical system of a turbine generator and a series compensated transmission system.

~~Induction Generator Effect (IGE)~~

~~An electrical in which a resonance involving a Generation Resource and a series compensated transmission system results in electrical self-excitation of the Generation Resource at a subsynchronous frequency.~~

~~Torque Amplification~~

~~An interaction between Generation Resources and a series compensated transmission system in which the response results in higher transient torque during or after disturbances than would otherwise occur.~~

~~Subsynchronous Control Interaction (SSCI)~~

~~The interaction between a series capacitor compensated transmission system and the control system of Generation Resources.~~

Subsynchronous ~~Resonance~~ Oscillation (SSO~~R~~) Countermeasures

Any equipment or any procedure to mitigate the SSO~~R~~ vulnerability, including but not limited to the following types of countermeasures:

Subsynchronous ~~Resonance~~Oscillation (SSO~~R~~) Protection

A countermeasure that includes, but is not limited to, disconnecting the affected equipment, Load, ~~or~~ Generation Resource, or Energy Storage Resource (ESR).

Board Report

Subsynchronous ~~Resonance~~Oscillation (SSO~~R~~) Mitigation

A countermeasure that includes, but is not limited to, equipment installation, controller adjustment, or a procedure to mitigate the SSO~~R~~ vulnerability without disconnecting the affected equipment, Load, ~~or~~ Generation Resources, or ESRs.

~~**Transmission Service Bus (TSB)**~~

~~The Electrical Bus in the Transmission Service Provider (TSP) substation that is electrically closest to the Service Delivery Point for a Load, or any electrically equivalent Electrical Bus in that substation.~~

2.2 ACRONYMS AND ABBREVIATIONS

ILLE	Interconnecting Large Load Entity
LLIS	Large Load Interconnection Study
SSFR	Subsynchronous Ferroresonance
~~**TSB**~~	~~Transmission Service Bus~~

3.1.1 Role of ERCOT

(1) ERCOT shall coordinate and use reasonable efforts, consistent with Good Utility Practice, to accept, approve or reject all requested Outage plans for maintenance, repair, and construction of both Transmission Facilities and Resources within the ERCOT System. ERCOT may reject an Outage plan under certain circumstances, as set forth in these Protocols.

(2) ERCOT's responsibilities with respect to Outage Coordination include:

(a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) in coordination with and based on information regarding all Entities' Planned Outages and Maintenance Outages;

[NPRR857: Replace paragraph (a) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(a) Approving or rejecting requests for Planned Outages and Maintenance Outages of Transmission Facilities for Transmission Service Providers (TSPs) and Direct Current Tie Operators (DCTOs) in coordination with and based on information regarding all Entities' Planned Outages and Maintenance Outages;

(b) Assessing the adequacy of available Resources, based on planned and known Resource Outages, relative to forecasts of Load, Ancillary Service requirements, and reserve requirements;

(c) Coordinating all Planned Outage and Maintenance Outage plans and approving or rejecting Outage plans for Planned Outages of Resources;

(d) Coordinating and approving or rejecting Outage plans for Planned Outages of Reliability Must-Run (RMR) Units under the terms of the applicable RMR Agreements;

(e) Coordinating and approving or rejecting Outage plans associated with Black Start Resources under the applicable Black Start Unit Agreements;

(f) Coordinating and approving or rejecting Outage plans affecting Subsynchronous Resonance (SSR) vulnerable Generation Resources that do not have SSO~~R~~ Mitigation in the event of five or six concurrent transmission Outages;

[NPRR1246: Replace paragraph (f) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(f) Coordinating and approving or rejecting Outage plans affecting Subsynchronous Resonance (SSR) vulnerable Generation Resources and Energy Storage Resources (ESRs) that do not have SSO~~R~~ Mitigation in the event of five or six concurrent transmission Outages;

(g) Coordinating and approving or rejecting changes to existing Resource Outage plans;

(h) Monitoring how Planned Outage schedules compare with actual Outages;

(i) Posting all proposed and approved schedules for Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities on the Market Information System (MIS) Secure Area under Section 3.1.5.13, Transmission Report;

(j) Creating and posting aggregated MW of Planned Outages for Resources on the MIS Secure Area under Section 3.2.3, Short-Term System Adequacy Reports;

(k) Monitoring Transmission Facilities and Resource Forced Outages and Maintenance Outages of immediate nature and implementing responses to those Outages as provided in these Protocols;

(l) Establishing and implementing communication procedures:

(i) For a TSP to request approval of Transmission Facilities Planned Outage and Maintenance Outage plans; and

[NPRR857: Replace item (i) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(i) For a TSP or a DCTO to request approval of Transmission Facilities Planned Outage and Maintenance Outage plans; and

(ii) For a Resource Entity's designated Single Point of Contact to submit Outage plans and to coordinate Resource Outages;

(m) Establishing and implementing record-keeping procedures for retaining all requested Planned Outages, Maintenance Outages, Rescheduled Outages, and Forced Outages; and

(n) Planning and analyzing Transmission Facilities Outages.

3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests

(1) ERCOT shall evaluate requests, approve, or reject Transmission Facilities Planned Outages and Maintenance Outages according to the requirements of this section. ERCOT may approve Outage requests provided the Outage in combination with other proposed Outages does not cause a violation of applicable reliability standards. ERCOT shall reject Outage requests that do not meet the submittal timeline specified in Section 3.1.5.12, Submittal Timeline for Transmission Facility Outage Requests. ERCOT shall consider the following factors in its evaluation:

(a) Forecasted conditions during the time of the Outage;

(b) Outage plans submitted by Resource Entities and TSPs under Section 3.1, Outage Coordination;

[NPRR857: Replace item (b) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(b) Outage plans submitted by Resource Entities, TSPs, and DCTOs under Section 3.1, Outage Coordination;

(c) Forced Outages of Transmission Facilities;

(d) Potential for the proposed Outages to cause irresolvable transmission overloads or voltage supply concerns based on the indications from contingency analysis software;

(e) Potential for the proposed Outages to cause SSR vulnerability to Generation Resources that do not have SSO~~R~~ Mitigation in the event of five or six concurrent transmission Outages;

[NPRR1246: Replace item (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(e) Potential for the proposed Outages to cause SSR vulnerability to Generation Resources or ESRs that do not have SSO~~R~~ Mitigation in the event of five or six concurrent transmission Outages;

(f) Previously approved Planned Outages, Maintenance Outages, and Rescheduled Outages;

(g) Impacts on the transfer capability of Direct Current Ties (DC Ties); and

(h) Good Utility Practice for Transmission Facilities maintenance.

(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) When ERCOT approves a Maintenance Outage, ERCOT shall coordinate the timing of the appropriate course of action with the requesting TSP or DCTO.

(3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with TSP to make reasonable efforts to minimize the impact.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) When ERCOT identifies that an HIO has been submitted with 90-days or less notice, ERCOT may coordinate with the TSP or DCTO to make reasonable efforts to minimize the impact.

3.3.2 Types of Work Requiring ERCOT Approval

(1) Each TSP, QSE and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

[NPRR857: Replace paragraph (1) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, QSE, and Resource Entity shall coordinate with ERCOT the requirements of Section 3.10, Network Operations Modeling and Telemetry, the following types of work for any addition to, replacement of, or change to or removal from the ERCOT Transmission Grid:

(a) Transmission lines;

(b) Equipment including circuit breakers, transformers, disconnects, and reactive devices;

(c) Resource interconnections;~~ and~~

(d) Protection and control schemes, including changes to Remedial Action Plans (RAPs), Supervisory Control and Data Acquisition (SCADA) systems, Energy Management Systems (EMSs), Automatic Generation Control (AGC), Remedial Action Schemes (RASs), or Automatic Mitigation Plans (AMPs);~~.~~ <u>And</u>

(e) Large Load interconnections.

3.10.7.2 Modeling of Resources and Transmission Loads

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and the non-TSP owned MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

[NPRR995 and NPRR1246: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR995; upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1246:]

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, ESRs, SOGs, SOESSs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), Transmission ESRs (TESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), Settlement Only Transmission Energy Storage Systems (SOTESSs), and the non-TSP MPTs greater than ten MVA, must be modeled to provide equivalent generation injections to the ERCOT Transmission Grid. ERCOT shall coordinate the modeling of Generation Resources, ESRs, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

(2) Each Resource Entity representing either a Load Resource or an Aggregate Load Resource (ALR) shall provide ERCOT and, as applicable, its interconnecting DSP and TSP, with information describing each such Resource as specified in Section 3.7.1.2, Load Resource Parameters, and any additional information and telemetry as required by ERCOT, in accordance with the timelines set forth in Section 3.10.1, Time Line for Network Operations Model Changes. ERCOT shall coordinate the modeling of ALRs with Resource Entities. ERCOT shall coordinate with representatives of the Resource Entity to map Load Resources to their appropriate Load in the Network Operations Model.

(3) Each Resource Entity representing a Distribution Generation Resource (DGR) or Distribution Energy Storage Resource (DESR) that is registered with ERCOT pursuant to Section 16.5, Registration of a Resource Entity, shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its DGR or DESR facilities, and additional information and telemetry as required by ERCOT and the interconnecting DSP. ERCOT shall coordinate with

representatives of the Resource Entity to represent the registered DGR or DESR facilities at their appropriate Electrical Bus in the Network Operations Model.

(4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG facilities to their appropriate Load in the Network Operations Model.

[NPRR995: Replace paragraph (4) above with the following upon system implementation:]

(4) Each Resource Entity representing a Settlement Only Distribution Generator (SODG) or Settlement Only Distribution Energy Storage System (SODESS) facility that is registered with ERCOT pursuant to paragraph (5) of Section 16.5 shall provide ERCOT, its interconnecting DSP, and the TSP that interconnects the DSP to the transmission system with information describing each of its SODG or SODESS facilities, and additional information and telemetry as required by ERCOT. ERCOT shall coordinate with representatives of the Resource Entity to map registered SODG or SODESS facilities to their appropriate Load in the Network Operations Model.

(5) Each Resource Entity representing a Split Generation Resource shall provide information to ERCOT and TSPs describing an individual Split Generation Resource for its share of the generation facility to be represented in the Network Operations Model in accordance with Section 3.8, Special Considerations. The Split Generation Resource must be modeled as connected to the ERCOT Transmission Grid on the low side of the generation facility MPT.

(6) ERCOT shall create a DC Tie Resource to represent an equivalent generation injection to represent the flow into the ERCOT Transmission Grid from operation of DC Ties. The actual injection flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Resource output.

(7) Each TSP~~s~~ and, if applicable, Resource Entity shall provide ERCOT with the following information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same ~~transmission line~~bus to represent a ~~Model Load~~Load Point to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "~~Model Loads~~Load Points", which may be one or more combined Loads, for use in its Network Operations Model. A ~~Model Load~~Load Point cannot be used to represent Load connections that are in different Load Zones.

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to

cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(7) Each TSP and DCTO shall provide ERCOT with information describing all transmission Load connections on the ERCOT Transmission Grid. Individual Load connections may be combined, at the discretion of ERCOT, with other Load connections on the same transmission line to represent a ~~Model Load~~Load Point to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Load Points~~Model Loads~~", which may be one or more combined Loads, for use in its Network Operations Model. A ~~Model Load~~Load Point cannot be used to represent Load connections that are in different Load Zones.

(8) ERCOT may require TSPs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP shall notify ERCOT if the owner does not comply with the request.

[NPRR857: Replace paragraph (8) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(8) ERCOT may require TSPs and DCTOs to provide additional Load telemetry to provide adequate modeling of the transmission system in accordance with Section 3.10.7.5, Telemetry Standards. When the TSP or DCTO does not own the station for which additional Load telemetry is being requested, the TSP shall request that the owner make the telemetry available. The TSP or DCTO shall notify ERCOT if the owner does not comply with the request.

(9) ERCOT shall create a DC Tie Load to represent an equivalent Load withdrawal to represent the flow from the ERCOT Transmission Grid from operation of DC Ties. The actual withdrawal flow on the DC Tie from telemetry provided by the facility owner(s) is the DC Tie Load output.

(10) Each TSP shall also provide information to ERCOT describing automatic Load transfer (rollover) plans and the events that trigger which Loads are switched to other Transmission Elements on detection of Outage of a primary Transmission Element. ERCOT shall accommodate Load rollover plans in the Network Operations Model.

(11) Loads associated with a Generation Resource in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3.

[NPRR1246: Replace paragraph (11) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(11) Loads associated with a Generation Resource or ESR in a common switchyard as defined in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, and served through a transformer owned by the Resource Entity is treated as an auxiliary Load and must be netted first against any generation meeting the requirements under Section 10.3.2.3.

(12) If the Day-Ahead Market (DAM) determines, in the processing of Outages, that a Load Resource, DGR, or DESR is de-energized in the ERCOT Network Operations Model, the de-energized Resource will be eligible to receive Ancillary Service awards in the DAM, but will not be eligible to receive energy awards in the DAM.

(13) A Resource Entity may aggregate Intermittent Renewable Resource (IRR) generation equipment together to form an IRR (Wind-powered Generation Resource (WGR) or PhotoVoltaic Generation Resource (PVGR)) if the generation equipment is behind the same main power transformer and is the same model and size, and the aggregation does not reduce ERCOT's ability to model pre- and post-contingency conditions. A Resource Entity may also aggregate IRR generation equipment that is not the same model and size together with an existing IRR only if:

(a) The mix of IRR generation equipment models and sizes causes no degradation in the dynamic performance of the IRR represented by the parameters modeled by ERCOT in operational studies and the aggregation of IRR generation equipment does not limit ERCOT's ability to model the ERCOT Transmission Grid and the relevant contingencies required for monitoring pre- and post-contingency system limits and conditions;

(b) The mix of IRR generation equipment is included in the Resource Registration data submitted for the WGR;

(c) All relevant IRR generation equipment data requested by ERCOT is provided;

(d) With the addition of dissimilar IRR generation equipment, the existing IRR shall continue to meet the applicable Protocol performance requirements, including but not limited to Primary Frequency Response, dynamic capability and Reactive Power capability, at the POIB; and

(e) Either:

(i) No more than the lower of 5% or ten MW aggregate capacity is of IRR generation equipment that is not the same model or size from the other equipment within the existing IRR; or

(ii) The wind turbines that are not the same model or size meet the following criteria:

(A) The IRR generation equipment has similar dynamic characteristics to the existing IRR generation equipment, as determined by ERCOT in its sole discretion;

(B) The MW capability difference of each generator is no more than 10% of each generator's maximum MW rating; and

(C) For WGRs, the manufacturer's power curves for the wind turbines have a correlation of 0.95 or greater with the other wind turbines within the existing WGR over wind speeds of 0 to 18 m/s.

(14) For each Load Point within the ERCOT Network Operations Model, each TSP~~TOTSP~~ shall identify and provide an end-use industry classification when a~~the~~ Load Point ~~by itself or in combination with other Load Points in the same substation~~represents a single end-use Customer or Service Delivery Point~~site~~ that has an historical or~~,~~ requested~~, or expected~~ peak Demand of 25 MW or greater, either:

(a) By itself;

(b) In combination with other Load Points in the same substation that serve the same Customer ~~and/~~or Service Delivery Point;

(c) Where~~The TSP shall identify and classify a Load Point even if~~, in addition to a~~the~~ Customer or Service Delivery Point~~site~~ with a 25 MW or larger peak Demand, other Customers with historical or~~,~~ requested ~~, or expected~~ Demands smaller than 25 MW that are not required to be modeled also take service at the same Load Point; or~~.~~

(d) Where the single Customer ~~and/~~or Service Delivery Point is served by multiple substations.

~~(e) For instances where a wholesale point of delivery is provided by a TSP to a Distribution Service Provider (DSP):~~

~~(i) By March 1 of each year, the DSP shall provide a list of each Customer, including its end-use industry classification, that achieved a peak Demand of 25 MW or more during the previous calendar year to its interconnecting TSP and its TO; and~~

~~(ii) The TO that models the DSP's Load in the Network Operations Model shall identify each such Customer as a separate Load Point, including its end-use industry classification.~~

~~(f) Customers described by paragraph (14) shall be modeled according to the following schedule:~~

(15) The applicable TSP shall identify Load Points subject to the requirements of paragraph (14) above in the Network Operations Model according to the following schedule:

(a) Load Points associated with an interconnecting Customer with a requested peak Demand of 25 MW or greater shall be modeled prior to energization;

(b) Load Points associated with a Customer or Service Delivery Point with a historical peak Demand of 25 MW or greater achieved prior to January 1, 2025 shall be modeled via a spreadsheet NOMCR on or before September~~July~~ 1, 2025;

(i) For Customers or Service Delivery Points served by a Distribution Service Provider (DSP) via a wholesale point of delivery provided by a TSP, the DSP shall provide a list of Customers, including end-use industry classification, to the interconnecting TSP on or before August~~June~~ 1, 2025; and

(c) If not already modeled pursuant to paragraph (b) above, Load Points associated with a Customer or Service Delivery Point that achieves a peak Demand of 25 MW or greater on or after January 1, 2025 shall be modeled on or before April 1 of the next calendar year after the peak Demand reached 25 MW via a spreadsheet NOMCR;

(i) For Customers or Service Delivery Points served by a Distribution Service Provider (DSP) via a wholesale point of delivery provided by a TSP, the DSP shall provide a list of Customers, including end-use industry classification, to the interconnecting TSP on or before March 1.

~~***[NPRR1234: Insert paragraphs (i) and (ii) below upon system implementation but no earlier than January 1, 2027 and renumber accordingly :]***~~ ~~(i) Customers with a historical peak Demand of 25 MW or greater shall be modeled via a spreadsheet NOMCR;~~ ~~(ii) If not already modeled pursuant to paragraph (i) above, Customers that achieve a peak Demand of 25 MW or greater during a calendar year shall be modeled by March 31 of the following year via a spreadsheet NOMCR;~~

~~(i) Interconnecting Customers with a requested peak Demand of 25 MW or greater shall be modeled prior to energization.~~

(1~~5~~6) Each Resource Entity or IE ~~with~~ associated with an existing or proposed Generation Resource~~s~~ or ESR co-located with a Load as described in Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters, ~~will~~ shall represent the co-located Load using one or more Load Points that are separate from auxiliary Loads for the generator. ~~identify each Load Point served in the same substation as the Generation Resource when the~~If the aggregate co-located Load has a~~n~~ historical or ~~expected~~requested peak Demand of 25 MW or greater~~.~~, ~~T~~the ~~Resource Entity~~Resource Entity or IE shall provide the end-use industry classification best representing the facility for each Load Point that is not an auxiliary Load. Calculation of peak Demand shall exclude the auxiliary Loads associated with Generation Resources or ESRs ~~from the determination of the peak Demand and shall not identify the associated Load Points in the ERCOT Network Operations Model. The Resource Entity or IE shall provide the end-use industry classification best representing the facility and may use the same designation for each identified Load Point.~~

(17) A Resource Entity or IE with co-located Load that has a historical or requested peak Demand of 25 MW or greater provide end-use industry classification according to the following schedule:

(a) The classification of a new co-located Load associated with a new generation interconnection request or with an operational Generation Resource or ESR shall be provided in the Resource Registration data and included in the Network Operations Model prior to energization of the co-located Load;

(b) The classification of an operational co-located Load with a historical peak Demand of 25 MW or greater achieved prior to January 1, 2025 shall be provided via an update to the Resource Registration data on or before September~~July~~ 1, 2025;

(c) The classification of an operational co-located Load that achieves a peak Demand of 25 MW or greater on or after January 1, 2025 shall be provided via an update to the Resource Registration data within three months from the date peak Demand reaches 25 MW;

(18) ERCOT shall treat Load Point identification and end-use classification provided pursuant to paragraphs (14) through (17) of this Section as "Proprietary Customer Information," as defined in paragraph (1)(r) of Section 1.3.1.1, Items Considered Protected Information.

(~~16~~19) Each Large Load connected at transmission voltage shall be represented by a single Load Point or multiple Load Points at a single substation in the ERCOT Network Operations Model. No other Loads shall be included in these Load Points.

3.10.7.5 Telemetry Requirements

(1) The telemetry provided to ERCOT necessary to support the State Estimator must meet the requirements set forth in Section 3.10.9, State Estimator Requirements.

(2) The telemetry provided to ERCOT by each TSP and QSE must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP and QSE

shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP and QSE. ERCOT shall represent data condition codes from each TSP and QSE in a consistent manner for all applicable ERCOT applications.

[NPRR857: Replace paragraph (2) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(2) The telemetry provided to ERCOT by each TSP, QSE, or DCTO must be updated at a ten second or less scan rate and be provided to ERCOT at the same rate. Each TSP, DCTO, and QSE shall install appropriate condition detection capability to notify ERCOT of potentially incorrect data from loss of communication or scan function. Condition codes must accompany the data to indicate its quality and whether the data has been measured within the scan rate requirement. Also, ERCOT shall analyze data received for possible loss of updates. Similarly, ERCOT shall provide condition detection capability on loss of telemetry links with the TSP, DCTO, and QSE. ERCOT shall represent data condition codes from each TSP, DCTO, and QSE in a consistent manner for all applicable ERCOT applications.

(3) Each TSP and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

[NPRR857: Replace paragraph (3) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the

interconnection; and (b) The financial security required to fund the interconnection facilities:]

(3) Each TSP, DCTO, and QSE shall use fully redundant ICCP links between its control center systems and ERCOT systems such that any single element of the communication system can fail and:

(a) For server failures, complete information must be re-established within five minutes by automatic failover to alternate server(s); and

(b) For all other failures, complete information must continue to flow between the TSP's, DCTO's, QSE's, and ERCOT's control centers with updates of all data continuing at a 30 second or less scan rate.

(4) When ERCOT identifies a reliability concern, a deficiency in system observability, or a deficiency in measurement to support the representation of Load Points~~Model Loads~~, and that concern or deficiency is not due to any inadequacy of the State Estimator program, additional telemetry may be requested as described in Section 3.10.7.5.9, ERCOT Requests for Telemetry.

3.10.7.5.1 Continuous Telemetry of the Status of Breakers and Switches

(1) Each TSP and QSE shall be responsible for providing telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource owns, respectively, used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP or Resource Entity switching operations and TSP or Resource Entity personnel.

(3) Each TSP, Resource Entity, or QSE shall update the status of any breaker or switch it owns or is responsible for through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Load Points~~Model Loads~~ in LMP results versus the cost to remedy.

(b) If the TSP or QSE disputes the request for additional telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

[NPRR857: Replace paragraphs (1) through (4) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(1) Each TSP, DCTO, and QSE shall provide telemetry, as described in this subsection, to ERCOT on the status of all breakers and switches it owns or its Resource Entity owns, respectively used to switch any Transmission Element or Load modeled by ERCOT.

(2) Each TSP, DCTO, and QSE is not required to install telemetry on individual breakers and switches it owns or its Resource Entity owns, respectively, where the telemetered status shown to ERCOT is current and free from ambiguous changes in state caused by the TSP, DCTO, or QSE switching operations and TSP, DCTO, or QSE personnel.

(3) Each TSP, DCTO, and QSE shall update the status of any breaker or switch it owns or its Resource Entity owns, respectively, through manual entries, if necessary, to communicate the actual current state of the device to ERCOT, except if the change in state is expected to return to the prior state within one minute.

(4) If in the sole opinion of ERCOT, the manual updates of the TSP, DCTO, or QSE have been unsuccessful in maintaining the accuracy required to support State Estimator performance to a TAC-approved predefined standard as described in Section 3.10.9, State Estimator Requirements, ERCOT may request that the TSP, DCTO, or QSE install complete telemetry from the breaker or switch it owns or its Resource Entity owns, respectively, to the TSP, DCTO, or QSE, and then to ERCOT.

(a) In making the determination to request installation of additional telemetry from a breaker or switch, ERCOT shall consider the economic implications of inaccurate representation of Load Points~~Model Loads~~ in LMP results versus the cost to remedy.

(b) If the TSP or associated QSE disputes the request for additional telemetry it owns or its Resource Entity owns, respectively, it may appeal the request pursuant to Section 3.10.7.5.9, ERCOT Requests for Telemetry.

(5) ERCOT shall measure TSP and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

[NPRR857: Replace paragraph (5) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(5) ERCOT shall measure TSP, DCTO, and QSE performance in providing accurate data that do not include ambiguous changes in state and shall report the performance metrics on the MIS Secure Area on a monthly basis.

(6) Unless there is an Emergency Condition, TSPs and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

[NPRR857: Replace paragraph (6) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(6) Unless there is an Emergency Condition, TSPs, DCTOs, and QSEs must obtain approval from ERCOT to purposely open a breaker or switch unless that breaker or switch is shown in a Planned Outage in the Outage Scheduler, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker. Also, TSPs, DCTOs, and QSEs must obtain approval from ERCOT before closing any breaker or switch, except in response to a Forced Outage, or an emergency, or the device will return to its previous state within 60 minutes, or the device is a generator output circuit breaker.

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the

device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

[NPRR857: Replace paragraph (7) above with the following upon system implementation and satisfying the following conditions: (1) Southern Cross provides ERCOT with funds to cover the entire estimated cost of the project; and (2) Southern Cross has signed an interconnection agreement with a TSP and the TSP gives ERCOT written notice that Southern Cross has provided it with: (a) Notice to proceed with the construction of the interconnection; and (b) The financial security required to fund the interconnection facilities:]

(7) ERCOT shall monitor the data condition codes of all breakers and switches showing loss of communication or scan function in the Network Operations Model. When the telemetry of breakers and switches is lost, ERCOT shall use the last known state of the device for security analysis as updated by the Outage Scheduler and through verbal communication with the TSP, DCTO, or QSE. ERCOT's systems must identify probable errors in switch or breaker status and ERCOT shall act to resolve or correct such errors in a timely manner as described in Section 6, Adjustment Period and Real-Time Operations.

(8) ERCOT shall establish a system that provides alarms to ERCOT Operators when there is a change in status of any monitored transmission breaker or switch, and an indication of whether the device change of status was planned in the Outage Scheduler. ERCOT Operators shall monitor any changes in status not only for reliability of operations, but also for accuracy and impact on the operation of the SCED functions and subsequent potential for calculation of inaccurate LMPs.

(9) Each QSE that represents a Split Generation Resource, with metering according to Section 3.8, Special Considerations, shall provide ERCOT with telemetry of the actual generator breakers and switches continuously providing ERCOT with the status of the individual Split Generation Resource.

3.15 Voltage Support

Commented [CP2]: Please note NPRR1272 also proposes revisions to this section.

(1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it on the Market Information System (MIS) Secure Area. ERCOT, the interconnecting TSP, or that TSP's agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions.

[NPRR1240: Replace paragraph (i) above with the following upon system implementation:]

(1) ERCOT, in coordination with the Transmission Service Providers (TSPs), shall establish and update, as necessary, the ERCOT System Voltage Profile and shall post it

on the ERCOT website. ERCOT, the interconnecting TSP, or that TSP's agent, may modify the Voltage Set Point described in the Voltage Profile based on current system conditions.

(2) All Generation Resources (including self-serve generating units) and Energy Storage Resources (ESRs) that are connected to Transmission Facilities and that have a gross unit rating greater than 20 MVA or those units connected at the same Point of Interconnection Bus (POIB) that have gross unit ratings aggregating to greater than 20 MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service (VSS).

(3) Except as reasonably necessary to ensure reliability or operational efficiency, TSPs should utilize available static reactive devices prior to requesting a Voltage Set Point change from a Generation Resource or ESR.

(4) Each Generation Resource and ESR required to provide VSS shall comply with the following Reactive Power requirements in Real-Time operations when issued a Voltage Set Point by a TSP or ERCOT:

(a) An over-excited (lagging or producing) power factor capability of 0.95 or less determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 0.95 per unit to 1.04 per unit, as measured at the POIB;

(b) An under-excited (leading or absorbing) power factor capability of 0.95 or less, determined at the unit's maximum net power to be supplied to the ERCOT Transmission Grid and for any Voltage Set Point from 1.0 per unit to 1.05 per unit, as measured at the POIB;

(c) For any Voltage Set Point outside of the voltage ranges described in paragraphs (a) and (b) above, the Generation Resource or ESR shall supply or absorb the maximum amount of Reactive Power available within its inherent capability and the capability of any VAr-capable devices as necessary to achieve the Voltage Set Point;

(d) When a Generation Resource or an ESR required to provide VSS is issued a new Voltage Set Point, that Generation Resource or ESR shall make adjustments in response to the new Voltage Set Point, regardless of whether the current voltage is within the tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements;

(e) For Generation Resources, the Reactive Power capability shall be available at all MW output levels and may be met through a combination of the Generation Resource's Corrected Unit Reactive Limit (CURL), which is the generating unit's dynamic leading and lagging operating capability, and/or dynamic VAr-capable devices. This Reactive Power profile is depicted graphically as a rectangle. For Intermittent Renewable Resources (IRRs), the Reactive Power requirements shall be available at all MW output levels at or above 10% of the IRR's nameplate capacity. When an IRR is operating below 10% of its nameplate capacity and is unable to support voltage at the POIB, ERCOT, the interconnecting TSP, or that TSP's agent may require an IRR to disconnect from the ERCOT System for purposes of maintaining reliability. For ESRs, the Reactive Power capability shall be available at all MW levels, when charging or discharging, and may be met through a combination of the ESR's CURL, and/or dynamic VAr-capable devices. For any ESR that achieved Initial Synchronization before December 16, 2019, the requirement to have Reactive Power capability when charging does not apply if the Resource Entity for the ESR has submitted a notarized attestation to ERCOT stating that, since the date of Initial Synchronization, the ESR has been unable to comply with this requirement without physical or software changes/modifications, and ERCOT has provided written confirmation of the exemption to the Resource Entity. The exemption shall apply only to the extent of the ESR's inability to comply with the requirement when the ESR is charging.

(f) For any Generation Resource or Energy Storage Resource (ESR) that is part of a Self-Limiting Facility, the capabilities described in paragraphs (a) and (b) above shall be determined based on the Self-Limiting Facility's established MW Injection limit and, if applicable, established MW Withdrawal limit.

(5) As part of the technical Resource testing requirements prior to the Resource Commissioning Date, all Generation Resources and ESRs must conduct an engineering study, and demonstrate through performance testing, the ability to comply with the Reactive Power capability requirements in paragraph (4), (7), (8), or (9) of this Section, as applicable. Any study and testing results must be accepted by ERCOT prior to the Resource Commissioning Date.

(6) Except for a Generation Resource or an ESR subject to Planning Guide Section 5.2.1, Applicability, a Generation Resource or an ESR that has already been commissioned is not required to submit a new reactive study or conduct commissioning-related reactive testing, as described in paragraph (5) above.

(7) Wind-powered Generation Resources (WGRs) that commenced operation on or after February 17, 2004, and have a signed Standard Generation Interconnection Agreement (SGIA) on or before December 1, 2009 ("Existing Non-Exempt WGRs"), must be capable of producing a defined quantity of Reactive Power to maintain a set point in the Voltage Profile established by ERCOT in accordance with the Reactive Power requirements established in paragraph (4) above, except in the circumstances described in paragraph (a) below.

(a) Existing Non-Exempt WGRs whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above must conduct an engineering study using the Summer/Fall 2010 on-peak/off-peak Voltage Profiles, or conduct performance testing to determine their actual Reactive Power capability. Any study or testing results must be accepted by ERCOT. The Reactive Power requirements applicable to these Existing Non-Exempt WGRs will be the greater of: the leading and lagging Reactive Power capabilities established by the Existing Non-Exempt WGR's engineering study or testing results; or Reactive Power proportional to the real power output of the Existing Non-Exempt WGR (this Reactive Power profile is depicted graphically as a triangle) sufficient to provide an over-excited (lagging) power factor capability of 0.95 or less and an under-excited (leading) power factor capability of 0.95 or less, both determined at the WGR's set point in the Voltage Profile established by ERCOT, and both measured at the POIB.

(i) Existing Non-Exempt WGRs shall submit the engineering study results or testing results to ERCOT no later than five Business Days after its completion.

(ii) Existing Non-Exempt WGRs shall update any and all Resource Registration data regarding their Reactive Power capability documented by the engineering study results or testing results.

(iii) If the Existing Non-Exempt WGR's engineering study results or testing results indicate that the WGR is not able to provide Reactive Power capability that meets the triangle profile described in paragraph (a) above, then the Existing Non-Exempt WGR will take steps necessary to meet that Reactive Power requirement depicted graphically as a triangle by a date mutually agreed upon by the Existing Non-Exempt WGR and ERCOT. The Existing Non-Exempt WGR may meet the Reactive Power requirement through a combination of the WGR's Unit Reactive Limit (URL) and/or automatically switchable static VAr-capable devices and/or dynamic VAr-capable devices. No later than five Business Days after completion of the steps to meet that Reactive Power requirement, the Existing Non-Exempt WGR will update any and all Resource Registration data regarding its Reactive Power and provide written notice to ERCOT that it has completed the steps necessary to meet its Reactive Power requirement.

(iv) For purposes of measuring future compliance with Reactive Power requirements for Existing Non-Exempt WGRs, results from performance testing or the Summer/Fall 2010 on-peak/off-peak Voltage Profiles utilized in the Existing Non-Exempt WGR's engineering study shall be the basis for measuring compliance, even if the Voltage Profiles provided to the Existing Non-Exempt WGR are revised for other purposes.

(b) Existing Non-Exempt WGRs whose current design allows them to meet the Reactive Power requirements established in paragraph (4) above (depicted graphically as a rectangle) shall continue to comply with that requirement. ERCOT, with cause, may request that these Existing Non-Exempt WGRs provide further evidence, including an engineering study, or performance testing, to confirm accuracy of Resource Registration data supporting their Reactive Power capability.

(8) Qualified Renewable Generation Resources (as described in Section 14, State of Texas Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the ERCOT Operating Guides.

(9) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made prior to February 17, 2004, based upon previous standards, whose design does not allow them to meet the Reactive Power requirements established in paragraph (4) above, will be required to maintain a Reactive Power requirement as defined by the Generation Resource's URL that was submitted to ERCOT and established per the criteria in the Operating Guides.

(10) For purposes of meeting the Reactive Power requirements in paragraphs (4) through (9) above, multiple units including IRRs shall, at a Resource Entity's option, be treated as a single Resource if the units are connected to the same transmission bus.

(11) Resource Entities may submit to ERCOT specific proposals to meet the Reactive Power requirements established in paragraph (4) above by employing a combination of the CURL and added VAr capability, provided that the added VAr capability shall be automatically switchable static and/or dynamic VAr devices. A Resource Entity and TSP may enter into an agreement in which the proposed static VAr devices can be switchable using Supervisory Control and Data Acquisition (SCADA). ERCOT may, at its sole discretion, either approve or deny a specific proposal, provided that in either case, ERCOT shall provide the submitter an explanation of its decision.

(12) A Resource Entity and TSP may enter into an agreement in which the Generation Resource or ESR compensates the TSP to provide VSS to meet the Reactive Power requirements of paragraph (4) above in part or in whole. The TSP shall certify to ERCOT that the agreement complies with the Reactive Power requirements of paragraph (4).

(13) Unless specifically approved by ERCOT, no unit equipment replacement or modification at a Generation Resource or ESR shall reduce the capability of the unit below the Reactive Power requirements that applied prior to the replacement or modification. The addition of 20 MW or more of Load to a site that includes one or more Generation Resources or ESRs constitutes a modification to the Generation Resource or ESR that requires a new Reactive Power study.

(14) Generation Resources or ESRs shall not reduce high reactive loading on individual units during abnormal conditions without the consent of ERCOT unless equipment damage is imminent.

(15) All WGRs must provide a Real-Time SCADA point that communicates to ERCOT the number of wind turbines that are available for real power and Reactive Power injection into the ERCOT Transmission Grid. WGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The number of wind turbines that are not able to communicate and whose status is unknown; and

(b) The number of wind turbines out of service and not available for operation.

(16) All PhotoVoltaic Generation Resources (PVGRs) must provide a Real-Time SCADA point that communicates to ERCOT the capacity of PhotoVoltaic (PV) equipment that is available for real power and Reactive Power injection into the ERCOT Transmission Grid. PVGRs must also provide two other Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of PV equipment that is not able to communicate and whose status is unknown; and

(b) The capacity of PV equipment that is out of service and not available for operation.

[NPRR1029: Insert paragraph (17) below upon system implementation and renumber accordingly:]

(17) Each DC-Coupled Resource must provide a Real-Time SCADA point that communicates to ERCOT the capacity of the intermittent renewable generation component of the Resource that is available for real power and/or Reactive Power injection into the ERCOT System. Each DC-Coupled Resource must also provide Real-Time SCADA points that communicate to ERCOT the following:

(a) The capacity of any PV generation equipment that is not able to communicate and whose status is unknown;

(b) The capacity of any PV generation equipment that is out of service and not available for operation;

(c) The number of any wind turbines that are not able to communicate and whose status is unknown; and

(d) The number of any wind turbines out of service and not available for operation.

(17) For the purpose of complying with the Reactive Power requirements under this Section 3.15, Reactive Power losses that occur on privately-owned transmission lines behind the POIB may be compensated by automatically switchable static VAr-capable devices.

Board Report

3.15.3 Generation Resource and Energy Storage Resource Requirements Related to Voltage Support

(1) Generation Resources and ESRs required to provide VSS shall have and maintain Reactive Power capability at least equal to the Reactive Power capability requirements specified in these Protocols and the ERCOT Operating Guides.

(2) Generation Resources and ESRs providing VSS shall be compliant with the ERCOT Operating Guides for response to transient voltage disturbance.

(3) Generation Resources and ESRs providing VSS must meet technical requirements specified in Section 8.1.1.1, Ancillary Service Qualification and Testing, and the performance standards specified in Section 8.1.1, QSE Ancillary Service Performance Standards.

(4) Each Generation Resource and ESR providing VSS shall operate with the unit's Automatic Voltage Regulator (AVR) in the automatic voltage control mode unless specifically directed to operate in manual mode by ERCOT, or when the unit is telemetering its Resource Status as STARTUP, SHUTDOWN, or ONTEST, or the QSE determines a need to operate in manual mode due to an undue threat to safety, undue risk of bodily harm, or undue damage to equipment at the generating plant.

(5) Each Generation Resource and ESR providing VSS shall maintain the Voltage Set Point established by ERCOT, the interconnecting TSP, or the TSP's agent, subject to the Generation Resource's or ESR's operating characteristic limits, voltage limits, and within tolerances identified in paragraph (4) of Nodal Operating Guide Section 2.7.3.5, Resource Entity Responsibilities and Generation Resource and Energy Storage Resource Requirements.

(6) The reactive capability required must be maintained at all times that the Generation Resource or ESR is On-Line.

(7) Each QSE shall send to ERCOT, via telemetry, the AVR and Power System Stabilizer (PSS) status for each of its Generation Resources providing VSS. Each QSE shall send to ERCOT via telemetry the AVR status for each of its ESRs providing VSS. For AVRs, an "On" status will indicate the AVR is on and set to regulate the Resource's terminal voltage in the voltage control mode, and an "Off" status will indicate the AVR is off or in a manual mode. For PSS, an "On" status will indicate the service is enabled and ready for service, and an "Off" status will indicate it is off or out of service. Each QSE shall monitor the status of its Generation Resources' and ESRs' regulators and stabilizers, and shall report status changes to ERCOT.

(8) Each Resource Entity shall provide information related to the tuning parameters, local or inter-area, of any PSS installed at a Generation Resource.

(9) If any individual Resource within a Self-Limiting Facility is incapable of meeting its Reactive Power requirement at the POI, the QSE must bring On-Line additional

Resource(s) within the Self-Limiting Facility to provide VSS as specified in paragraph (4) of Section 3.15, Voltage Support, while respecting the limit on MW Injection.

(10) The Resource Entity for an IRR synchronized to the ERCOT System that is not capable of providing Reactive Power when not producing real power shall:

(a) When capable of providing real power, set the IRR's Low Sustained Limit (LSL) to 0 MW, or the lowest MW level, not to exceed 1 MW, at which the IRR can provide stable Reactive Power after appropriate tuning of settings;

(b) Ensure the lowest MW point on the submitted reactive capability curve reflects 0 MVAr leading and lagging reactive capability at 0 MW;

(c) Ensure the second-lowest MW point on the submitted reactive capability curve accurately reflects the IRR's leading and lagging reactive capability at its LSL when the LSL is not 0 MW; and

(d) Send to ERCOT, via telemetry, an AVR status of "Off" when the IRR is synchronized to the ERCOT System and not producing Reactive Power.

(11) The Resource Entity for an IRR synchronized to the ERCOT System that is capable of providing any net Reactive Power when not producing real power shall:

(a) Provide stable Reactive Power output at all MW levels at which the IRR has Reactive Power capability;

(b) When capable of providing real power, set the IRR LSL to 0 MW or the lowest MW level, not to exceed 1 MW, at which the IRR can provide stable Reactive Power after appropriate tuning of settings;

(c) Ensure the lowest MW point on the submitted reactive capability curve accurately reflects the IRR's MVAr leading and lagging reactive capability when not producing real power;

(d) Ensure the second-lowest MW point on the submitted reactive capability curve accurately reflects the IRR's leading and lagging reactive capability at its LSL when the LSL is not 0 MW;

(e) Send to ERCOT, via telemetry, an AVR status of "On" when the IRR is synchronized to the ERCOT System, not producing real power, and reactive control is working properly; and

(f) Meet the requirements in paragraphs (2), (4), (5), and (7) above when the IRR is synchronized to the ERCOT System and not producing real power.

(12) The Resource Entity for an IRR that is capable of providing any net Reactive Power when not producing real power may physically desynchronize its inverters from the ERCOT System instead of providing Reactive Power when not producing real power.

(13) A Resource Entity shall submit a new Reactive Power study for a Generation Resource or ESR if 20 MW or more of Load is added to a site that includes the Generation Resource or ESR.

3.22 Subsynchronous ~~Resonance~~Oscillation

(1) All series capacitors shall have automatic Subsynchronous ~~Resonance~~Oscillation (SSO~~R~~) protective relays installed and shall have remote bypass capability. The SSO~~R~~ protective relays shall remain in-service when the series capacitors are in-service.

3.22.1 Subsynchronous ~~Resonance~~Oscillation Vulnerability Assessment

(1) In the SSO~~R~~ vulnerability assessment, each transmission circuit is considered as a single Outage. A common tower Outage of two circuits or the Outage of a double-circuit transmission line will be considered as two transmission Outages.

(2) The SSO vulnerability assessment includes the Subsynchronous Resonance (SSR) vulnerability assessment that is related to the interaction between Generation Resources and series capacitors.

3.22.1.1 Existing Generation Resource Assessment

(1) ERCOT shall perform a one-time SSR vulnerability assessment on all existing Generation Resources as described in paragraphs (a) through (f) below. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, on or before August 12, 2013.

(a) ERCOT shall perform a topology ~~-~~check on all existing Generation Resources.

(b) If during the topology ~~-~~check ERCOT determines that an existing Generation Resource will become radial to ~~a~~one or more series capacitor~~(s)~~ in the event of ~~less than~~ 14 or fewer concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous ~~Resonance~~Oscillation Vulnerability Assessment Criteria, and will provide the frequency scan assessment results to the affected Resource Entity.

(c) If the frequency scan assessment described in paragraph (b) above indicates potential SSR vulnerability, the Transmission Service Provider(s) (TSP(s)) that owns the affected series capacitor(s), in coordination with the interconnecting TSP, shall perform a detailed SSR analysis in accordance with Section 3.22.2 to determine SSR vulnerability, unless ERCOT, in consultation with and in agreement with of the affected TSP(s) and the affected Resource Entity, determines the frequency scan assessment is sufficient to determine the SSR vulnerability.

(d) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of four or ~~less~~fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor(s) shall coordinate with the interconnecting TSP, ERCOT, and the affected Resource Entity to develop and implement SS~~R~~O Mitigation on the ERCOT transmission system.

(e) If the SSR study performed in accordance with paragraph (b) and/or (c) above indicates that an existing Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring.

(f) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

3.22.1.2 Generation Resource or Energy Storage Resource Interconnection Assessment

(1) In the security screening study for a Generation~~ Resource~~ Interconnection or Modification~~Change Request~~ (GIM), ERCOT will perform a topology~~ -~~check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to ~~a~~one or more series capacitor~~(s)~~ in the event of fewer than 14 concurrent transmission Outages.

[NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) In the security screening study for a Generation ~~Resource/Energy Storage Resource~~ Interconnection or Modification~~Change Request~~ (GIM), ERCOT will perform a topology~~ -~~check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to ~~a~~one or more series capacitor~~(s)~~ in the event of fewer than 14 concurrent transmission Outages.

(2) If ERCOT identifies that a Generation Resource or ESR will become radial to ~~a~~one or more series capacitor~~(s)~~ in the event of fewer than 14 concurrent transmission Outages, the interconnecting TSP shall perform an SSR study including frequency scan assessment and/or detailed SSR assessment for the Interconnecting Entity (IE) in accordance with Section 3.22.2, Subsynchronous ~~Resonance~~Oscillation Vulnerability Assessment Criteria, to determine SSR vulnerability. The SSR study shall determine which system configurations create vulnerability to SSR. Alternatively, if the IE can demonstrate to ERCOT's and the interconnecting TSP's satisfaction that the Generation Resource or ESR is not vulnerable to SSR, then the interconnecting TSP is not required to perform the SSR study. If an SSR study is conducted, the interconnecting TSP shall submit it to ERCOT upon completion and shall include any SSO~~R~~ Mitigation plan developed by the IE that has been reviewed by the TSP.

(3) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of six or fewer concurrent transmission Outages, the IE shall develop an SSO~~R~~ Mitigation plan, provide it to the interconnecting TSP for review and inclusion in the TSP's SSR study report to be approved by ERCOT, and implement the SSO~~R~~ Mitigation prior to Initial Synchronization.

(a) If the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of four concurrent transmission Outages, the IE may install SSO~~R~~ Protection in lieu of SSO~~R~~ Mitigation, as required by paragraph (3) above, if:

(i) The Generation Resource or ESR satisfied Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, between August 12, 2013 and March 20, 2015;

(ii) The SSO~~R~~ Protection is approved by ERCOT; and

(iii) The Generation Resource or ESR installs the ERCOT-approved SSO~~R~~ Protection prior to Initial Synchronization.

(b) For any Generation Resource or ESR that satisfied Planning Guide Section 6.9 before September 1, 2020, if the SSR study performed in accordance with paragraph (2) above indicates that the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, the IE may elect not to develop or implement an SSO~~R~~ Mitigation plan, in which case ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring. The IE shall provide ERCOT written Notice of any such election before the Generation Resource or ESR achieves Initial Synchronization, and the Generation Resource or ESR shall not be permitted to proceed to Initial Synchronization until ERCOT has implemented SSR monitoring.

(4) ERCOT shall respond with its comments or approval of an SSR study report, which should include any required SSO~~R~~ Mitigation plan, within 30 days of receipt. ERCOT comments should be addressed as soon as practicable by the TSP, and any action taken in response to ERCOT's comments on an SSR study report shall be subject to further ERCOT review and approval. Upon approval of the SSR study report, ERCOT shall notify the interconnecting TSP, and the interconnecting TSP shall provide the approved SSR study report to the IE.

3.22.1.3 Transmission Project Assessment

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSO~~R~~ vulnerability assessment, including a topology ~~-~~check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous ~~Resonance~~Oscillation Vulnerability Assessment Criteria. The TSP shall include a summary of the results of this assessment in the project submission to the Regional

Planning Group (RPG) pursuant to Section 3.11.4, Regional Planning Group Project Review Process. For Tier 4 projects that include Transmission Facilities connecting to or operating at 345 kV, the TSP shall provide the SSO~~R~~ assessment for ERCOT's review. For the purposes of this Section, a Generation Resource is considered an existing Generation Resource if it satisfies Planning Guide Section 6.9 at the time the Transmission Facilities are proposed.

[NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSO~~R~~ vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous ~~Resonance~~Oscillation Vulnerability Assessment Criteria. The TSP shall include a summary of the results of this assessment in the project submission to the Regional Planning Group (RPG) pursuant to Section 3.11.4, Regional Planning Group Project Review Process. For Tier 4 projects that include Transmission Facilities connecting to or operating at 345 kV, the TSP shall provide the SSO~~R~~ assessment for ERCOT's review. For the purposes of this Section, a Generation Resource or Energy Storage Resource (ESR) is considered an existing Generation Resource or ESR if it satisfies Planning Guide Section 6.9 at the time the Transmission Facilities are proposed.

(2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource, ~~or~~ a Generation Resource satisfying Planning Guide Section 6.9, an existing Large Load, or a Large Load satisfying Planning Guide Sections 9.4, LLIS Report and Follow-up, and 9.5, Interconnection Agreements and Responsibilities, at the time the transmission project is proposed to become vulnerable to SSO~~R~~, ERCOT shall perform an SSO~~R~~ vulnerability assessment, including topology -check and frequency scan in accordance with Section 3.22.2 if such an assessment was not included in the project submission. ERCOT shall include a summary of the results of this assessment in the independent review.

[NPRR1246: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) If while performing the independent review of a transmission project, ERCOT determines that the transmission project may cause an existing Generation Resource or ESR or a Generation Resource or ESR satisfying Planning Guide Section 6.9, an existing Large Load, or a Large Load satisfying Planning Guide Sections 9.4, LLIS Report and Follow-up, and 9.5, Interconnection Agreements and Responsibilities, at the time the transmission project is proposed to become vulnerable to SSO~~R~~, ERCOT shall perform an SSO~~R~~ vulnerability assessment, including topology-check and frequency scan in accordance with Section 3.22.2 if such an assessment was not

included in the project submission. ERCOT shall include a summary of the results of this assessment in the independent review.

(3) If the frequency scan assessment in paragraphs (1) or (2) above indicates potential SSO~~R~~ vulnerability in accordance with Section 3.22.2, the TSP(s) that owns the affected series capacitor(s), in coordination with the TSP proposing the Transmission Facilities, shall perform a detailed SSO~~R~~ assessment to confirm or refute the SSO~~R~~ vulnerability.

(4) Past SSO~~R~~ assessments may be used to determine the SSO~~R~~ vulnerability of a Generation Resource or a Large Load if ERCOT, in consultation with the affected TSPs, determines the results of the past SSO~~R~~ assessments are still valid.

[NPRR1246: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) Past SSO~~R~~ assessments may be used to determine the SSO~~R~~ vulnerability of a Generation Resource, ~~or~~ ESR, or a Large Load if ERCOT, in consultation with the affected TSPs, determines the results of the past SSO~~R~~ assessments are still valid.

(5) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of four or ~~less~~fewer concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and implement SSO~~R~~ Mitigation on the ERCOT transmission system. The SSO~~R~~ Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

[NPRR1246: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(5) If the SSR study confirms a Generation Resource or ESR is vulnerable to SSR in the event of four or ~~less~~fewer concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and implement SSO~~R~~ Mitigation on the ERCOT transmission system. The SSO~~R~~ Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(6) If the SSR study confirms a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

[NPRR1246: Replace paragraph (6) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) If the SSR study confirms a Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(7) If the SSO study confirms a Large Load is vulnerable to SSO in the event of six or fewer concurrent transmission Outages, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Interconnecting Large Load Entity (ILLE), and affected TSPs to develop and implement SSO Mitigation on the ERCOT transmission system. The SSO Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Energization of the Large Load.

(8) If the SSO study confirms one or more transformers associated with the Large Load is vulnerable to Sub-synchronous Ferroresonance (SSFR) in the event of one or more conditions listed below, the TSP that owns the affected series capacitor(s) shall coordinate with ERCOT, the affected Interconnecting Large Load Entity (ILLE), and affected TSPs to develop and implement SSO Mitigation on the ERCOT transmission system. The SSO Mitigation shall be developed prior to RPG acceptance, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Energization of the Large Load.

(a) One single element outage;

(b) One common tower outage;

(c) Two single element outages;

(d) Two common tower outages; or

(e) One single element outage and one common tower outage.

(9~~7~~) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, at its sole discretion, may extend the response deadline.

3.22.1.4 Large Load Interconnection Assessment

(1) Upon completion of all requirements prescribed in Planning Guide Section 9.2.2, Submission of Large Load Project Information and Initiation of the Large Load Interconnection Study (LLIS), ERCOT shall perform a topology check to determine:

(a) If the Large Load will become radial to one or more series capacitors in the event of six or fewer concurrent transmission Outages; and

(b) Whether the Large Load or any associated Facilities are expected to be susceptible to SSO.

(2) ~~The interconnecting TSP shall provide all information requested by~~ ERCOT shall specify all of the information that is needed to perform the topology check detailed in paragraph (1) above, and provide this specification to the interconnecting TSP. The interconnecting TSP shall request this information from the ILLE~~,~~ and provide it to ERCOT once received. ERCOT shall not initiate the topology check until it receives the required information from the TSP.

(3) The interconnecting TSP shall perform a detailed SSO assessment for the Load connection in accordance with Section 3.22.2, Subsynchronous Oscillation Vulnerability Assessment Criteria, to determine SSO vulnerability, if ERCOT determines that:

(a) A Large Load is vulnerable to SSO in the event of six or fewer concurrent transmission Outages; or

(b) A transformer associated with a Large Load is vulnerable to SSFR in the event of the following:

(i) One single element outage;

(ii) One common tower outage;

(iii) Two single element outages;

(iv) Two common tower outages; or

(v) One single element outage and one common tower outage.

(4) The SSO study shall determine which system configurations create vulnerability to SSO. The interconnecting TSP shall submit both the study report and the model data used in the study to ERCOT upon completion of the study. ~~and~~ The interconnecting TSP shall include in the study report any SSO Countermeasures that have been reviewed by the TSP.

(5) If the SSO study performed in accordance with paragraph (3) above indicates that the Load connection is vulnerable to SSO, the ILLE~~, in coordination with the interconnecting TSP,~~, in coordination with the interconnecting TSP, shall develop an SSO Countermeasure plan~~, provide it to the interconnecting TSP for review,~~ and the TSP shall include it in the SSO study report to be approved by ERCOT.

(6) ERCOT shall respond with its comments or approval of an SSO study report, which shall include any required SSO Countermeasure plan, within 30 days of receipt. ERCOT comments shall be addressed as soon as practicable by the TSP, and any action taken in

response to ERCOT's comments on an SSO study report shall be subject to further ERCOT review and approval. Upon approval of the SSO study report, ERCOT shall notify the interconnecting TSP.

~~(7) ERCOT shall specify the model data necessary for the ILLE to interconnect, and provide this specification to the interconnecting TSP. The interconnecting TSP shall request this information from the ILLE, and provide itprovide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline if the ILLE does not provide the required information to the interconnecting TSP within this timeframe, or for any other appropriate reason.~~

(~~8~~7) After ERCOT approval of the SSO study report, the ILLE, in coordination with the interconnecting TSP, shall implement the approved SSO Countermeasures prior to Initial Energization of the Large Load.

3.22.1.5~~4~~ Annual SSO~~R~~ Review

(1) ERCOT shall perform an SSO~~R~~ review annually. The annual review shall include the following elements:

(a) The annual review shall include a topology ~~-~~check applying the system network topology that is consistent with a year 3 Steady State Working Group (SSWG) base case developed in accordance with Planning Guide Section 6.1, Steady-State Model Development. ERCOT shall post the SSO~~R~~ annual topology ~~-~~check report to the Market Information System (MIS) Secure Area by May 31 of each year.

(b) If ERCOT identifies that a Generation Resource will become radial to series capacitors(s) in the event of ~~less than~~ 14 or fewer concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. ERCOT shall prepare a report to summarize the results of the frequency scan assessment and provide it to the Resource Entity and the affected TSP.

(i) If the frequency scan assessment described in paragraph (b) above shows the Generation Resource has potential SSR vulnerability in the event of six or fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor compensated Transmission Element in coordination with the interconnecting TSP shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(ii) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(iii) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of four or ~~less~~fewer concurrent transmission Outages, the TSP that owns the affected series capacitor compensated Transmission Element shall coordinate with ERCOT, the affected Resource Entity, and affected

TSPs to develop and install SSO~~R~~ Mitigation on the ERCOT transmission system. The SSO~~R~~ Mitigation shall be developed, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource.

(iv) If the SSR study confirms the Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of energization of the transmission project or the Initial Synchronization of the Generation Resource.

(v) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline.

[NPRR1246: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(b) If ERCOT identifies that a Generation Resource or ESR will become radial to series capacitors(s) in the event of ~~less than~~ 14 or fewer concurrent transmission Outages, ERCOT shall perform a frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria. ERCOT shall prepare a report to summarize the results of the frequency scan assessment and provide it to the Resource Entity and the affected TSP.

(i) If the frequency scan assessment described in paragraph (b) above shows the Generation Resource or ESR has potential SSR vulnerability in the event of six or fewer concurrent transmission Outages, the TSP(s) that owns the affected series capacitor compensated Transmission Element in coordination with the interconnecting TSP shall perform a detailed SSR assessment to confirm or refute the SSR vulnerability.

(ii) Past SSR assessments may be used to determine the SSR vulnerability of a Generation Resource or ESR if ERCOT, in consultation with the affected TSPs, determines the results of the past SSR assessments are still valid.

(iii) If the SSR study confirms the Generation Resource or ESR is vulnerable to SSR in the event of four or fewer~~less~~ concurrent transmission Outages, the TSP that owns the affected series capacitor compensated Transmission Element shall coordinate with ERCOT, the affected Resource Entity, and affected TSPs to develop and install SSO~~R~~ Mitigation on the ERCOT transmission system. The SSO~~R~~ Mitigation shall be developed, if required, and implemented prior to the latter of the energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(iv) If the SSR study confirms the Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages, ERCOT shall implement SSR monitoring in accordance with Section 3.22.3, Subsynchronous Resonance Monitoring, prior to the latter of energization of the transmission project or the Initial Synchronization of the Generation Resource or ESR.

(v) The Resource Entity shall provide sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline.

(c) ERCOT shall perform a topology check to identify any Large Load that becomes radial to one or more series capacitors in the event of six or fewer concurrent transmission Outages. ERCOT shall prepare a report to summarize the results of the topology check and provide it to the affected TSP. ERCOT and the affected TSP shall determine a need for further evaluation.

(i) If an SSO study confirms the Large Load or any associated Facilities are vulnerable to SSO and this risk was not previously identified during any study required by Section 3.22.1.4, the TSP that owns the affected series capacitor shall conduct more detailed study by coordinat~~e~~ing with ERCOT, the affected ILLE, and affected TSPs to develop and install SSO Countermeasures on the ERCOT transmission system. The SSO Countermeasures shall be implemented prior to the latter of the energization of the transmission project or Initial Energization of the Large Load.

(ii) The interconnecting TSP shall submit both the detailed study report and the model data used in the detailed study to ERCOT upon completion of the study. The interconnecting TSP shall include in the study report any SSO Countermeasures that have been reviewed by the TSP. ~~ERCOT shall specify the model data necessary for the ILLE to interconnect, and provide this specification to the interconnecting TSP. The interconnecting TSP shall request this information from the ILLE, and provide it~~provide ~~sufficient model data to ERCOT within 60 days of receipt of the data request. ERCOT, in its sole discretion, may extend the response deadline if the ILLE does not provide the required information to the interconnecting TSP within this timeframe, or for any other appropriate reason.~~

3.22.2 Subsynchronous ~~Resonance~~Oscillation Vulnerability Assessment Criteria

(1) A Generation Resource is considered to be potentially vulnerable to SSR in the topology -check if a Generation Resource will become radial to ~~a~~ one or more series capacitors~~(s)~~ in the event of ~~less than~~ 14 or fewer concurrent transmission Outages. A frequency scan assessment and/or a detailed SSR assessment shall be required to screen for system conditions causing potential SSR vulnerability.

[NPRR1246: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) A Generation Resource or ESR is considered to be potentially vulnerable to SSR in the topology-check if the Generation Resource or ESR will become radial to ~~a~~one or more series capacitors~~(s)~~ in the event of ~~less than~~ 14 or fewer concurrent transmission Outages. A frequency scan assessment and/or a detailed SSR assessment shall be required to screen for system conditions causing potential SSR vulnerability.

(2) A Large Load is considered to be potentially vulnerable to SSO in the topology check if:

(a) A Large Load will become radial to one or more series capacitors in the event of six or fewer concurrent transmission Outages; or

(b) A transformer associated with a Large Load will become radial to one or more series capacitors in the event of the following:

(i) One single element outage;

(ii) One common tower outage;

(iii) Two single element outages;

(iv) Two common tower outages; or

(v) One single element outage and one common tower outage.

(3~~2~~) In determining whether a Generation Resource is considered to be potentially vulnerable to SSR in the frequency scan assessment results, the following criteria shall be considered:

[NPRR1246: Replace paragraph (3~~2~~) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3~~2~~) In determining whether a Generation Resource or ESR is considered to be potentially vulnerable to SSR in the frequency scan assessment results, the following criteria shall be considered:

(a) Induction Generator Effect (IGE) and Subsynchronous Control Interaction (SSCI):

(i) When considering the total impedance of the generator and the applicable part of the ERCOT System, if the total resistance is negative at a reactance crossover of zero Ohms from negative to positive with increasing frequency, then the generator is considered to be potentially vulnerable to IGE/SSCI;

(b) Torsional Interaction:

(i) If the sum of the electrical damping (De) plus the mechanical damping (Dm) results in a negative value then the generator is potentially vulnerable to Torsional Interaction. Dm at +/- 1 Hz of the modal frequency may be utilized to compare to De; and

(c) Torque Amplification:

(i) When considering the total impedance of the generator and the ERCOT system, if a 5% or greater reactance dip, or a reactance crossover of zero Ohms from negative to positive with increasing frequency, occurs within a +/- 3 Hz complement of the modal frequency, then the generator is considered to be potentially vulnerable to Torque Amplification. The percentage of a reactance dip is on the basis of the reactance maximum at the first inflection point of the dip where the reactance begins to decrease with increasing frequency.

(4~~3~~) The detailed SSO~~R~~ assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource, ESR, or Large Load is considered to be vulnerable to SSO~~R~~ if any of the following criteria are met:

[NPRR1246: Replace paragraph (4~~3~~) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4~~3~~) The detailed SSO~~R~~ assessment shall include an electromagnetic transient program analysis or similar analysis. A Generation Resource, ~~or~~ ESR, or Large Load is considered to be vulnerable to SSO~~R~~ if any of the following criteria are met:

(a) For a Generation Resource, t~~T~~he SSR vulnerability results in more than 50% of fatigue life expenditure over the expected lifetime of the unit;

(i) If the fatigue life expenditure is not available, the highest torsional torque caused by SSR is more than 110% of the torque experienced during a transmission fault with the series capacitors bypassed;

(b) For a Generation Resource, an ESR, or a Large Load, t~~T~~he oscillation, if ~~occurred~~any, is not damped; or

(c) For a Generation Resource, an ESR, or a Large Load, t~~T~~he oscillation, if ~~occurred~~any, results in disconnection of any transmission ~~and~~or generation facilities.

3.22.3 Subsynchronous Resonance Monitoring

(1) For purposes of SSR monitoring, a common tower Outage loss of a double-circuit transmission line consisting of two circuits sharing a tower for 0.5 miles or greater is considered as one contingency.

(2) ERCOT's responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSO~~R~~ Mitigation:

(a) ERCOT shall identify the combinations of Outages of Transmission Elements that may result in SSR vulnerability and provide these Transmission Elements to the affected Resource Entity and its interconnected TSP;

(b) ERCOT shall monitor the status of these Transmission Elements identified in paragraph (a) above;

(c) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being three contingencies away from SSR vulnerability, ERCOT will identify options for mitigation that would be implemented if an additional transmission Outage were to occur, including communications with TSPs to determine potential Outage cancellations and time estimates to reinstate Transmission Facilities;

(d) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource. ERCOT shall consider the actions in the following order unless reliability considerations dictate a different order. Actions that may be considered are:

(i) No action if the affected Generation Resource is equipped with SSO~~R~~ Protection and has elected for ERCOT to forego action to mitigate SSR vulnerability;

(ii) Coordinate with TSPs to withdraw or restore an Outage within eight hours if feasible;

(iii) If the actions described in (i) and (ii) above are not feasible, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitors(s); or

(iv) Other actions specific to the situation, including, but not limited to, Verbal Dispatch Instruction (VDI) to the Resource's Qualified Scheduling Entity (QSE).

(e) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being one contingency away from SSR vulnerability, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitor(s).

(f) If the occurrence of Forced and/or Planned Outages results in a Generation Resource being two or ~~less~~fewer contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource by voice communication as soon as practicable that the SSR vulnerability scenario has occurred; initiate the mitigation actions described in paragraphs (2)(d)(i) through (iv) above; and provide additional notifications to the QSE of each relevant topology change until the affected Generation Resource(s) is at least three contingencies away from SSR vulnerability.

[NPRR1246: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) ERCOT's responsibilities for SSR monitoring shall consist of the following activities if a Generation Resource or ESR is vulnerable to SSR in the event of five or six concurrent transmission Outages identified in the SSR vulnerability assessment and does not implement SSO~~R~~ Mitigation:

(a) ERCOT shall identify the combinations of Outages of Transmission Elements that may result in SSR vulnerability and provide these Transmission Elements to the affected Resource Entity and its interconnected TSP;

(b) ERCOT shall monitor the status of these Transmission Elements identified in paragraph (a) above;

(c) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being three contingencies away from SSR vulnerability, ERCOT will identify options for mitigation that would be implemented if an additional transmission Outage were to occur, including communications with TSPs to determine potential Outage cancellations and time estimates to reinstate Transmission Facilities;

(d) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being two contingencies away from SSR vulnerability, ERCOT shall take action to mitigate SSR vulnerability to the affected Generation Resource or ESR. ERCOT shall consider the actions in the following order unless reliability considerations dictate a different order. Actions that may be considered are:

(i) No action if the affected Generation Resource or ESR is equipped with SSR Protection and has elected for ERCOT to forego action to mitigate SSO~~R~~ vulnerability;

(ii) Coordinate with TSPs to withdraw or restore an Outage within eight hours if feasible;

(iii) If the actions described in (i) and (ii) above are not feasible, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitors(s); or

(iv) Other actions specific to the situation, including, but not limited to, Verbal Dispatch Instruction (VDI) to the Resource's Qualified Scheduling Entity (QSE).

(e) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being one contingency away from SSR vulnerability, ERCOT shall promptly take necessary steps to identify and mitigate the impacts to the ERCOT System caused by bypassing the affected series capacitor(s) and direct the TSP(s) to bypass the affected series capacitor(s).

(f) If the occurrence of Forced and/or Planned Outages results in a Generation Resource or ESR being two or fewer~~less~~ contingencies away from SSR vulnerability, ERCOT shall notify the QSE representing the affected Generation Resource or ESR by voice communication as soon as practicable that the SSR vulnerability scenario has occurred; initiate the mitigation actions described in paragraphs (2)(d)(i) through (iv) above; and provide additional notifications to the QSE of each relevant topology change until the affected Generation Resource(s) or ESR(s) are at least three contingencies away from SSR vulnerability.

16.5 Registration of a Resource Entity

Commented [CP3]: Please note NPRR1265 also proposes revisions to this section.

(1) A Resource Entity owns or controls a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT's reasonable

satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource or SOG through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. A Resource Entity may submit a proposal to register a SOG consisting of an Energy Storage System (ESS) or a combination of ESS and non-ESS generation. The Resource Entity must identify all components of the SOG as part of the Resource Registration process.

[NPRR995: Replace paragraph (1) above with the following upon system implementation:]

(1) A Resource Entity owns or controls a Generation Resource, Energy Storage Resource (ESR), Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or Load Resource connected to the ERCOT System. Each Resource Entity operating in the ERCOT Region must register with ERCOT. To become registered as a Resource Entity, an Entity must execute a Standard Form Market Participant Agreement (using the form in Section 22, Attachment A, Standard Form Market Participant Agreement), designate Resource Entity Authorized Representatives, contacts, and a User Security Administrator (USA) (per the Application for Registration as a Resource Entity), and demonstrate to ERCOT's reasonable satisfaction that it is capable of performing the functions of a Resource Entity under these Protocols. The Resource Entity shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, for each Resource, SOG, or SOESS through ERCOT registration, except for Distributed Generation (DG) with an installed capacity equal to or lower than the DG registration threshold that has chosen not to register with ERCOT. A Resource Entity may submit a proposal to register the aggregation of generators, with the exception of Intermittent Renewable Resources (IRRs) pursuant to paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, as an Aggregate Generation Resource (AGR) which ERCOT may grant at its sole discretion. If a Resource Entity intends to register one or more Energy Storage Systems (ESSs) and one or more non-ESS generators as SOGs at the same site, the Resource Entity must provide an affidavit attesting to the amount of ESS and non-ESS capacity at the site as a condition for registration.

(2) Prior to commissioning, Resources Entities will regularly update the data necessary for modeling. These updates will reflect the best available information at the time submitted.

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, or SOG meets the requirements of Planning Guide Section

6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, or SOG in Exhibit "C" (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2 to assess whether the Generation Resource, ESR, or SOG, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, or SOG within 90 days of the date the Generation Resource, ESR, or SOG meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, or SOG violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]

(3) Once ERCOT has received a new or amended Standard Generation Interconnection Agreement (SGIA) or a letter from a duly authorized official from the Municipally Owned Utility (MOU) or Electric Cooperative (EC) and has determined that the proposed Generation Resource, ESR, SOG, or SOESS meets the requirements of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, ERCOT shall review the description of the proposed Generation Resource, ESR, SOG, or SOESS in Exhibit "C" (or similar exhibit) to the SGIA and the data submitted pursuant to Planning Guide Section 6.8.2, to assess whether the Generation Resource, ESR, SOG, or SOESS, as proposed, would violate any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents. ERCOT must provide its determination to the Transmission Service Provider (TSP) and the owner of the proposed Generation Resource, ESR, SOG, or SOESS within 90 days of the date the Generation Resource, ESR, SOG, or SOESS meets the conditions for review. Notwithstanding the foregoing, this determination shall not preclude ERCOT from subsequently determining that the Generation Resource, ESR, SOG, or SOESS violates any operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents or from taking any appropriate action based on that determination.

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), or Settlement Only Transmission Self-Generator (SOTSG) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, or SOTSG may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT's satisfaction that the Generation Resource, ESR, SOTG, or SOTSG can comply with these standards;

(b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, or SOTSG; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSR Mitigation Plan, SSR Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

[NPRR995: Replace paragraph (4) above with the following upon system implementation:]

(4) An Interconnecting Entity (IE) shall not proceed to Initial Synchronization of a Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), or Settlement Only Transmission Energy Storage System (SOTESS) in the event of any of the following conditions:

(a) Pursuant to paragraph (3) above, ERCOT has reasonably determined that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS may violate operational standards established in the Protocols, Planning Guide, Nodal Operating Guides, and Other Binding Documents, and the Resource Entity has not yet demonstrated to ERCOT's satisfaction that the Generation Resource, ESR, SOTG, SOTSG, or SOTESS can comply with these standards;

(b) The requirements of Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if applicable, have not been completed for the Generation Resource, ESR, SOTG, SOTSG, or SOTESS; or

(c) Any required Subsynchronous Resonance (SSR) studies, SSO~~R~~ Mitigation Plan, SSO~~R~~ Protection, and SSR monitoring if required, have not been completed and approved by ERCOT.

(5) DG with an installed capacity greater than one MW, the DG registration threshold, which exports energy into a Distribution System, must register with ERCOT.

(6) A Resource Entity representing an ESR shall register the ESR as an ESR. ERCOT systems, including the Energy and Market Management System (EMMS) and Settlement system, shall continue to treat the ESR as both a Generation Resource and a Controllable Load Resource until such time as all ERCOT systems are capable of treating an ESR as a single Resource.

[NPRR1246: Delete paragraph (6) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

ERCOT Fee Schedule

Effective TBD~~October 1, 2024~~

Commented [CP4]: Please note NPRR1202 also proposes revisions to this section.

Board Report

The following is a schedule of ERCOT fees currently in effect. These fees are not refundable unless ERCOT Protocols provide otherwise.

Description	Nodal Protocol Reference	Calculation/Rate/Comment
Private Wide Area Network (WAN) fees	9.16.2	Actual costs of procuring, using, maintaining, and connecting to the third-party communications networks and related hardware that provide ERCOT WAN communications. The portion of costs for ERCOT's work regarding an initial installation or reconfiguration of an existing installation will not exceed $7,000. The portion of the monthly network management fee for ERCOT's work will not exceed $450 per month.
ERCOT Load Resource Registration and Generator Interconnection or Modification fees	NA	$500 for registration of a new Load Resource. If a Resource Entity seeks to increase the MW size of an existing Load Resource by more than 20% or change the Load Resource's registration between non-Controllable Load Resource and Controllable Load Resource, it will incur a registration fee of $500. The term "generator," as used in this fee schedule relating to interconnection fees and Full Interconnection Study (FIS) Application fees, includes Generation Resources, Energy Storage Resources (ESRs), and Settlement Only Generators (SOGs) but, as reflected below, Settlement Only Distribution Generators (SODGs) will incur a different fee amount than transmission connected SOGs. The following fee amounts apply for the registration of a new generator: $2,300 for SODGs; $8,000 for generators that are less than 10 MW (other than SODGs); and $14,000 for generators that are 10 MW or greater. If a Resource Entity for an existing SODG seeks to change its registration to a Distribution Generation Resource (DGR) it will incur a registration fee of $8,000. If a Resource Entity seeks to make a modification that is covered by paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, to an existing generator it will incur a registration fee in association with the modification request. If, at the time the modification is submitted, the cumulative MW amount of the modification and any other modifications that have been submitted for that generator within the last 12 months amount to less than 10 MW, the registration fee will be $2,300. If, at the time the modification is submitted, the cumulative MW amount of the modification and any other modifications that have been submitted for that generator within the last 12 months amount to 10 MW or greater, the registration fee will be $14,000.

Full Interconnection Study (FIS) Application fee	NA	$3,000 for an FIS Application relating to a new generator. $2,700 for an FIS Application relating to modification of an existing generator.
Qualified Scheduling Entity (QSE) Application fee	9.16.2	$500 per Entity
Subordinate QSE (Sub-QSE) Application fee	9.16.2	$500 per Sub-QSE
Large Load Interconnection Study (LLIS) fee	NA	$14,000
Competitive Retailer (CR) Application fee	9.16.2	$500 per Entity
Congestion Revenue Right (CRR) Account Holder Application fee	9.16.2	$500 per Entity
Independent Market Information System Registered Entity (IMRE) fee	9.16.2	$500 per Entity
Resource Entity Application fee	9.16.2	$500 per Entity
Transmission and/or Distribution Service Providers (TDSPs)	9.16.2	$500 per Entity
Counter-Party Background Check fee	9.16.2	$350 per Principal
Weatherization Inspection fees	NA	Resource Entities with Generation Resources or ESRs and Transmission Service Providers (TSPs) shall pay fees to ERCOT for costs related to weatherization inspections conducted pursuant to 16 Texas Administrative Code (TAC) § 25.55, Weather Emergency Preparedness, as provided below. TSPs shall pay an inspection fee of $4,500 for each of their substations or switching stations that are inspected. Each Resource Entity to which this Section applies, other than those that own or control Generation Resources and ESRs that are federally owned, shall pay an inspection fee calculated as the Semiannual

		Generation Resource Inspection Costs * (Resource Entity MW Capacity/Aggregate MW Capacity). ERCOT will perform this calculation twice per calendar year and gather the necessary MW capacity data for that six-month period on one of the last 15 Business Days at the end of the period. Terms used in this formula are defined as follows: Semiannual Generation Resource Inspection Costs for purposes of this Section equals the sum of outside services costs, ERCOT internal costs, and overhead costs related to weatherization inspections, less inspection fees that will be invoiced to TSPs and Resource Entities with Generation Resources and ESRs that are federally owned, for that six-month period. Resource Entity MW Capacity for purposes of this Section equals the total MW capacity (using real power rating) associated with a Resource Entity with Generation Resources or ESRs. Aggregate MW Capacity for purposes of this Section equals the total MW capacity (using real power rating) of all the Resource Entities, other than Generation Resources and ESRs that are federally owned. Resource Entities with Generation Resources and ESRs that are federally owned shall pay an inspection fee of $4,500 for each of the Resources that are inspected. ERCOT will issue Invoices semiannually in the months of January and July for the preceding six-month period to the Resource Entities and TSPs that owe inspection fees. Payment of the fee will be due within 30 days of the Invoice date and late payments will incur 18% annual interest. Entities that fail to pay their Invoice on time will be publicly reported in a filing with the Public Utility Commission of Texas (PUCT). Further payment terms and instructions will be included on the Invoice.
Voluminous Copy fee	NA	$0.15 per page in excess of 50 pages
Actual Costs associated with Information Requests	NA	ERCOT will provide an estimate to the requestor of any vendor or third-party costs ERCOT deems appropriate to fulfill the information request. If the requestor approves the cost estimate, the requestor must pay all such costs as instructed by ERCOT before the information will be delivered to the requestor.
ERCOT Labor Costs for Information Requests	NA	$15 per hour of ERCOT time. If ERCOT determines that a request will involve a substantial burden on ERCOT employee or contractor time to fulfill the request, ERCOT will provide an estimate to the requestor of the anticipated labor costs. If the requestor approves the cost estimate, the requestor must pay all such labor costs as instructed by ERCOT before the information will be delivered to the requestor.

ERCOT Training fees for courses that award Continuing Education Hours (CEHs)	NA	$25 per North American Electric Reliability Corporation (NERC) CEH. Examples of such trainings include, without limitation, the Operator Training Seminar and Black Start Training.
Cybersecurity Monitor fee for Non-ERCOT Utilities that participate in the Texas Cybersecurity Monitor Program	NA	The Cybersecurity Monitor fee amount varies from year to year. The current fee amount is posted on ERCOT's website here: https://www.ercot.com/services/programs/tcmp

ERCOT Impact Analysis Report

NPRR Number	1234	NPRR Title	Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
Impact Analysis Date		May 28, 2024	
Estimated Cost/Budgetary Impact		Between $600k and $800k Annual Recurring Operations and Maintenance (O&M) Staffing Cost: $180k – $220k See ERCOT Staffing Impacts	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 12 to 18 months	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor There will be ongoing operational impacts to the following ERCOT departments totaling 10.7 Full-Time Employees (FTEs) to support this NPRR: • Large Load Integration (4.0 FTE effort) • Model Administration (1.0 FTE effort) • Network Model Maintenance (0.5 FTE effort) • Network Model Coordination (0.5 FTE effort) • Dynamic Studies (1.0 FTE effort) • Transmission Planning Assessment (1.0 FTE effort) • Operations Stability Analysis (2.2 FTE effort) • Resource Integration (0.5 FTE effort) ERCOT has assessed its ability to absorb the ongoing efforts of this NPRR with current staff and concluded the need for one additional FTE in Resource Integration: *980 hrs. to support the evaluation and approval of the reactive study and energization of large loads added to existing generators.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Resource Integration and Ongoing Operations (RIOO) 30% • Energy Management Systems 29% • Market Operation Systems 28% • Data Management & Analytic Systems 5% • Grid Modeling Systems 5% • Grid Decision Support Systems 1%	

	• Channel Management Systems 1% • ERCOT Website and MIS Systems 1%
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.
Grid Operations & Practices Impacts	ERCOT will update grid operations and practices to implement this NPRR.

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

Comments
None.

Board Report

NPRR Number	1241	NPRR Title	Firm Fuel Supply Service (FFSS) Availability and Hourly Standby Fee
Date of Decision		April 8, 2025	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		First of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Protocol Revision Request (NPRR) provides equity and clarity surrounding the hourly standby fee claw backs for Firm Fuel Supply Service (FFSS) during a Watch for winter weather using a linear curve formula.	
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	

Board Report

	(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	Based on experiences and performances during the 2023-2024 obligation period, there is one major area requiring further refinement and clarification. Luminant introduces a claw back and/or withholding amount of the Standby Fee that better aligns with the FFSS Resource's (FFSSR's) availability during a Watch issued for winter weather. Under this linear curve formula, FFSSRs could see a maximum claw back of 90 Operating Days for unavailability for greater than 50% of the hours. The reduction decreases to 18 days if an FFSSR is unavailable for 10% of the hours. Luminant believes this method encourages an FFSSR to work diligently to make an FFSSR available during a Watch while penalizing an FFSSR that is not available for most of a Watch.
PRS Decision	On 8/8/24, PRS voted unanimously to table NPRR1241 and refer the issue to WMS. All Market Segments participated in the vote. On 1/15/25, PRS voted to recommend approval of NPRR1241 as amended by the 12/3/24 Luminant comments. There was one abstention from the Consumer (Occidental) Market Segment. All Market Segments participated in the vote. On 2/12/25, PRS voted unanimously to endorse and forward to TAC the 1/15/25 PRS Report and 1/28/25 Impact Analysis for NPRR1241. All Market Segments participated in the vote.
Summary of PRS Discussion	On 8/8/24, the sponsor provided an overview of NPRR1241, and ERCOT Staff confirmed that fuel-related failures are not covered by NPRR1241 and would continue to receive a 90-day claw back. Participants requested additional review by WMS. On 1/15/25, participants reviewed the 12/3/24 Luminant comments and noted the WMS endorsement. On 2/12/25, there was no discussion.
TAC Decision	On 2/27/25, TAC voted unanimously to recommend approval of NPRR1241 as recommended by PRS in the 2/12/25 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 2/27/25, 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

	[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 4/8/25, the ERCOT Board voted unanimously to recommend approval of NPRR1241 as recommended by TAC in the 2/27/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1241 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1241.
ERCOT Opinion	ERCOT supports approval of NPRR1241.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1241 and believes the market impact for NPRR1241 maintains appropriate penalties for unavailability during a Watch for winter weather while providing improved incentives for impacted FFSSRs to restore their availability as soon as possible.

Sponsor	
Name	Katie Rich
E-mail Address	katie.rich@vistracorp.com
Company	Luminant Generation Company LLC
Phone Number	
Cell Number	737-313-9351
Market Segment	Independent Generator

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	cory.phillips@ercot.com

Board Report

Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**
WMS 091224	Requested PRS continue to table NPRR1241 for further review by the Wholesale Market Working Group (WMWG)
Luminant 120324	Proposed a linear curve formula to determine the amount of the claw back and/or withholding amount of the Standby Fee for FFSSRs that are unavailable during a Watch for winter weather
WMS 010925	Endorsed NPRR1241 as amended by the 12/3/24 Luminant comments

Market Rules Notes

Please note that the baseline Protocol language in Section 8.1.1.2.1.6 has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1231, FFSS Program Communication Improvements and Additional Clarifications (unboxed 11/15/24)

Proposed Protocol Language Revision

8.1.1.2.1.6 Firm Fuel Supply Service Resource Qualification, Testing, Decertification, and Recertification

(1) Generation Resources that meet the following requirements are eligible to provide Firm Fuel Supply Service (FFSS) and may be selected in the procurement process for FFSS. Both the primary Generation Resource and any alternate Generation Resources, as specified in the FFSS Offer Submission Form, must meet the following requirements prior to submitting an FFSS Offer Submission Form:

(a) Successfully demonstrates dual fuel capability, the ability to establish and burn an alternative onsite stored fuel, and has onsite fuel storage capability in an amount that satisfies the minimum FFSS capability requirements, as described in paragraph (2) below;

(b) Has an onsite natural gas or fuel oil storage capability or off-site natural gas storage where the Resource Entity and/or QSE owns and controls the natural gas storage and pipeline to deliver the required amount of reserve natural gas to the Generation Resource from the storage facility in an amount that satisfies the minimum FFSS capability requirements, as defined in paragraph (2) below; or

(c) Meets the following requirements:

(i) The Generation Entity for the Generation Resource (or an Affiliate of such Generation Entity) either owns a storage facility with, or has a Firm Gas Storage Agreement for, sufficient natural gas storage capacity for the offered Generation Resource to deliver the offered MW for the duration requirement specified in the request for proposal (RFP);

(ii) The Generation Entity for the Generation Resource (or an Affiliate of such Generation Entity) must own and have good title to sufficient natural gas in the storage facility for the offered Generation Resource to deliver the offered MW for at least the duration requirement specified in the RFP, and must commit to maintain such quantity of natural gas in storage at all times during the obligation period; and

(iii) The Generation Entity for the Generation Resource (or an Affiliate of such Generation Entity) must have entered into a Firm Transportation Agreement on an FFSS Qualifying Pipeline, or multiple Firm Transportation Agreements on multiple Qualifying Pipelines, and:

(A) Each Firm Transportation Agreement must have a maximum daily contract quantity sufficient to transport the quantity of natural gas described above from the storage facility to the Generation Resource in a quantity that is sufficient to allow generation of the offered FFSS MW for at least the duration requirement specified in the RFP;

(B) At least one of the Firm Transportation Agreements must contain a primary receipt point that is the point of withdrawal for the storage facility used to comply with paragraph (i) above;

(C) At least one of the Firm Transportation Agreements must contain a primary delivery point that permits delivery of the natural gas directly to the Generation Resource (including through a plant line or other dedicated lateral);

(D) Each Firm Transportation Agreement must have a term that includes each hour of November 15 through March 15, i.e., during the FFSS obligation period; and

(E) If multiple Firm Transportation Agreements will be used, the point of delivery for each Firm Transportation Agreement, other than the Firm Transportation Agreement that satisfies the requirements set forth in paragraph (C) above, must be a primary receipt point under another Firm Transportation Agreement such that there is a complete path for firm transportation service from the storage facility to the Generation Facility.

(iv) If the Generation Entity will utilize a contractual right to firm gas storage capacity on a third-party system under a Firm Gas Storage Agreement to comply with paragraph (i) above rather than a self-owned physical gas storage facility to qualify, then the Firm Gas Storage Agreement must have:

(A) A term that includes each hour of November 15 through March 15, i.e., during the FFSS obligation period;

(B) A maximum storage quantity not less than the amount of natural gas needed to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP;

(C) A maximum daily withdrawal quantity that permits the Generation Entity (or an Affiliate) to withdraw from storage a daily quantity of natural gas sufficient to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP; and

(D) A point of withdrawal that is a primary receipt point under its Firm Transportation Agreement.

(v) If the Generation Entity will utilize storage owned by it or an Affiliate to comply with paragraph (i) above, then the Generation Entity must certify that for the entire obligation period it or its Affiliate, as applicable, retains the rights to:

(A) Sufficient storage capacity in its facility to store not less than the amount of natural gas needed to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP;

(B) Withdraw from its storage a daily quantity of natural gas sufficient to allow the Generation Resource to deliver the offered MW for the duration requirement specified in the RFP; and

(C) Withdraw from its storage facility at a point of withdrawal that is a primary receipt point under its Firm Transportation Agreement.

(vi) The MW offered by the QSE for the Generation Resource may not be less than the Generation Resource's LSL.

(vii) The Generation Entity for the Generation Resource may satisfy the requirements set forth in paragraphs (i) through (v) above through use of a single, bundled agreement providing for gas supply, storage, and transportation service, as long as the bundled agreement satisfies the requirements of the definitions of Firm Transportation Agreement and Firm Gas Storage Agreement, the requirements in paragraphs (ii), (iii)(A), (iii)(D), (iv)(A), (iv)(B), and (iv)(C) above, and has a primary delivery point that permits delivery of the gas directly to the Generation Resource (including through a plant line or other dedicated lateral).

(d) A Generation Resource may participate as a Firm Fuel Supply Service Resource (FFSSR) under only one of paragraphs (a), (b), or (c) above.

(e) Successfully demonstrates the ability to provide FFSS in order to maintain Resource availability in the event of a natural gas curtailment or other fuel supply disruption consistent with qualifying technologies identified by the Public Utility Commission of Texas (PUCT).

(2) The minimum FFSS capability requirement is the volume of fuel necessary to operate the Generation Resource at the FFSS MW award level for the duration requirement specified in the RFP. This MW value must be greater than or equal to the Generation Resource's LSL and is a limit on the MW quantity of FFSS that can be offered for the Generation Resource in the FFSS Offer Submission Form.

(3) A Generation Resource will not be considered qualified to provide FFSS if, in a prior obligation period, the Generation Resource was decertified per paragraph (18) below. However, such Generation Resource may nevertheless be considered qualified to provide FFSS if the Generation Resource:

(a) Has subsequently been recertified, as provided in paragraph (22) below; or

(b) The QSE representing the Generation Resource submits a corrective action plan to ERCOT and has agreement with ERCOT on that plan.

(4) A Generation Entity may, but is not required to, submit in writing a proposed form of Firm Gas Storage Agreement or Firm Transportation Agreement (whether to be entered into by the Generation Entity or an Affiliate thereof) to ERCOT for review to be certified as an FFSS Qualified Contract in accordance with such policies and procedures as ERCOT may develop or require from time to time consistent with the requirements of the ERCOT Protocols.

(a) ERCOT may, but is not obligated to, undertake a review of such agreement and, if acceptable, certify in writing such agreement as an FFSS Qualified Contract. The decision whether to certify such agreement as an FFSS Qualified Contract shall be in ERCOT's sole discretion.

(b) To the extent that any such agreement is so certified by ERCOT, it shall constitute an FFSS Qualified Contract, and a Generation Entity may rely upon such certification for purposes of qualifying as an FFSSR under paragraph (1)(c) above. Any material change to the ERCOT certified form of an existing FFSS Qualified Contract that affects the requirements of a firm natural gas FFSSR shall require a re-certification by ERCOT. For the avoidance of doubt, a Firm Gas Storage Agreement or Firm Transportation Agreement meeting the requirements of the natural gas FFSSR is not required to be certified as an FFSS Qualified Contract.

(5) A QSE representing a Generation Resource that will be offered to provide FFSS as a primary Generation Resource or an alternate Generation Resource must annually demonstrate each offered Generation Resource's capability to use reserved fuel sources identified in paragraphs (1)(a) through (1)(c) above and sustain its output for 60 minutes at the MW value equal to the QSE's desired level of FFSS qualification for the Resource. The maximum MW of FFSS that can be offered for the designated Resource by the QSE must be limited to the average Real-Time net real power (in MW) telemetered for the Resource during the demonstration period. Each QSE representing an FFSSR or prospective FFSSR must annually complete the test or successfully deploy at the maximum awarded MW amount for at least the demonstration period and inform ERCOT by August 15 of each year. In order to complete this annual process, the QSE representing the Generation Resource(s) shall:

(a) If qualifying by a self-test, coordinate the test with the ERCOT control room and show the Resource as having a Resource Status of "ONTEST" in its COP and through its Real-Time telemetry for the duration of the demonstration; and

(b) Submit a Resource FFSS qualification form with the date and time of the self-test or the successful deployment that the QSE would like considered for qualification.

(6) A QSE representing an FFSSR must ensure the full awarded FFSS capability is available by November 15 of each year awarded in the RFP.

(7) A QSE representing an FFSSR shall update the Availability Plan for a Generation Resource to show it is unavailable to provide FFSS if it is not available to come On-Line or generate using reserved fuel. The QSE representing an FFSSR must submit an Availability Plan for any alternate Generation Resource that were designated in the FFSS Offer Submission Form. The QSE shall continue to show the Generation Resource is unavailable to provide FFSS in the Availability Plan until it can successfully come On-Line or generate using the reserved fuel.

(8) An FFSSR that is not available to come On-Line shall inform the ERCOT control room as soon as practicable and update the FFSSR Availability Plan within 60 minutes of identifying the unavailability.

(9) If the FFSSR is not available for the~~ percentage of~~ hours ~~outline below ~~for which ERCOT has issued a Watch for winter weather, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for ~~90~~athe number of days as calculated below~~listed below~~, unless the FFSSR exhausted the fuel reserved to generate at the FFSS MW award level for the duration requirement specified in the RFP, including any fuel that was restocked following final approval or instruction from ERCOT, or the FFSSR exhausted emission hours allocated for the FFSSR, as specified in the FFSS Offer Submission Form. Evidence of an FFSSR not being available includes, but is not limited to, an Availability Plan submission of unavailable or other communications to the ERCOT control room indicating the FFSSR is not available during the Watch. The number of days subject to claw back and/or withholding is calculated as follows~~The calculated claw back and/or~~

~~withholding amount of the FFSS Hourly Standby Fee for unavailability during a Watch shall be based on the following~~:

$FFSSDCB_{q,r} = Min(FFSSUFDW_{q,r} * 2, 1) * 90$

Where:

$FFSSUFDW_{q,r} = FFSSUHDW_{q,r} / FFSSDW$

The above variables are defined as follows:

Variable	Unit	Definition
$FFSSUFDW_{q,r}$	none	*Firm Fuel Supply Service Unavailability Factor per QSE per Resource*—The unavailability factor of Resource *r* represented by QSE *q* during a Watch for Winter Weather. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$FFSSUHDW_{q,r}$	hour	*Firm Fuel Supply Service Unavailable Hours per QSE per Resource*—The number of hours that the Resource *r* represented by QSE *q* was not available during a Watch for Winter Weather. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
FFSSDW	hour	*Firm Fuel Supply Service Duration of a Watch for Winter Weather*—The duration of a Watch for Winter Weather that occurs during a FFSS obligation period.
$FFSSDCB_{q,r}$	none	*Firm Fuel Supply Service Days to Claw Back*—The number of days subject to claw back for Resource *r* represented by QSE *q*, rounded to the nearest whole number. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
r	none	A primary or alternate Generation Resource approved by ERCOT to provide FFSS.

~~(a) Unavailability of FFSSR for greater than 75% of the hours results in a reduction for all Operating Days in the Obligation Period;~~

~~(b) Unavailability of FFSSR for greater than 50% and less than or equal to 75% of the hours results in a 90-day reduction;~~

~~(c) Unavailability of FFSSR for greater than 25% and less than or equal to 50% of the hours results in a 60-day reduction;~~

~~(d) Unavailability of FFSSR for greater than 10% and less than or equal to 25% of the hours results in a 30-day reduction; and~~

~~(e) Unavailability of FFSSR for greater than 0% and less than or equal to 10% of the hours results in a 10-day reduction.~~

(10) If the FFSSR fails to come On-Line or stay On-Line during an FFSS deployment due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days. A QSE representing an FFSSR may coordinate with ERCOT and seek approval to take the FFSSR Off-Line for no more than four hours to perform critical maintenance associated with consuming the reserved fuel. If the QSE coordinates with ERCOT and receives approval to take the FFSSR unit Off-Line and brings the FFSSR

back On-Line within four hours or less, this shall not count as failure to stay On-Line for the purpose of this paragraph.

(11) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment, but fails to telemeter on average an HSL equal to or greater than 95% of the awarded FFSS MW value due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days, in proportion to the difference between the awarded MW value and the average telemetered HSL over the FFSS deployment period.

(12) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a fuel-related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 90 days, in proportion to the difference between the average MW level instructed by ERCOT over the FFSS deployment period and the corresponding average generation of the FFSSR.

(13) If the FFSSR fails to come On-Line or stay On-Line during an FFSS deployment due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 15 days.

(14) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to telemeter on average an HSL equal to or greater than 95% of the awarded FFSS MW value due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 15 days, in proportion to the difference between the awarded MW value and the average telemetered HSL over the FFSS deployment period.

(15) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment but fails to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a non-fuel related issue, ERCOT shall claw back and/or withhold the FFSS Hourly Standby Fee for 15 days, in proportion to the difference between the average MW level instructed by ERCOT over the FFSS deployment period and the corresponding average generation of the FFSSR.

(16) Notwithstanding paragraphs (9) through (15) above, if the FFSSR is otherwise available but fails to come On-Line or is forced Off-Line due to a transmission system outage or transmission system limitation that would prevent the unit from being deployed to LSL, ERCOT shall not claw back the FFSS Hourly Standby Fee.

(17) If conditions described in paragraphs (11) and (12) occur for the same deployment period, ERCOT shall only claw back the larger amount calculated in paragraph (11) or (12). If conditions described in paragraphs (14) and (15) occur for the same deployment period, ERCOT shall only claw back the larger amount calculated in paragraph (14) or (15).

(18) ERCOT shall decertify a primary Generation Resource or any alternate Generation Resource that was an FFSSR for any of the following:

(a) Failure to come On-Line or stay On-Line during an FFSS deployment due to a fuel-related issue for two or more deployments;

(b) If the FFSSR comes On-Line or continues generating using reserved fuel during an FFSS deployment, failure to generate on average at the minimum of either 95% of the MW level instructed by ERCOT or 95% of the awarded FFSS MW value due to a fuel-related issue for two or more deployments; or

(c) Failure to maintain an Hourly Rolling Equivalent Availability Factor greater than or equal to 50%.

(19) If ERCOT decertifies a primary Generation Resource, the QSE shall designate an alternate Generation Resource that was awarded through the FFSS procurement process to replace the decertified Generation Resource and continue to provide FFSS. The designated alternate Generation Resource shall satisfy all of the requirements in paragraph (9) of Section 3.14.5, Firm Fuel Supply Service. The designated alternate Generation Resource may no longer be an alternate for another primary Generation Resource.

(20) If ERCOT decertifies an FFSSR that does not have any alternate Generation Resources that were awarded through the FFSS procurement process, ERCOT will cease payments to the QSE under Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery, until the FFSSR is recertified by ERCOT. ERCOT may issue one or more RFPs to replace the decertified FFSSR's capacity for the remainder of the FFSS obligation period.

(21) If ERCOT has not replaced a decertified Generation Resource's FFSSR capacity, the QSE of a decertified Generation Resource may request to reestablish its FFSSR certification by submitting a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and by successfully passing a new test, as described in paragraph (5) above. ERCOT shall, in its sole discretion, determine whether a Generation Resource shall be recertified.

(22) A decertified Generation Resource that has not been recertified by ERCOT must submit a corrective action plan to ERCOT and have agreement with ERCOT on that plan in order to be considered qualified to provide FFSS and be selected in the procurement process for any future FFSS obligation period.

(23) If an FFSSR is unavailable or fails to continuously deploy due to a Force Majeure Event, the Generation Entity for such Generation Resource must provide a report to ERCOT containing certain additional information, including:

(a) If the basis of the non-performance is a Force Majeure Event affecting the FFSSR, a description of the Force Majeure Event giving rise to the non-performance, with reasonably full details of such Force Majeure Event;

(b) If the basis of the non-performance is the unavailability of the FFSSR's FFSS Qualifying Pipeline or natural gas storage facility:

(i) A copy of the relevant Firm Transportation Agreement and/or Firm Gas Storage Agreement;

(ii) A copy of the nominations submitted or a detailed accounting of no notices volumes delivered for the gas day prior to the Force Majeure Event until the gas day after the Force Majeure Event;

(iii) The applicable storage inventory level for the gas day prior to the Force Majeure Event until the gas day after the Force Majeure Event;

(iv) A copy of the force majeure notice from the FFSS Qualifying Pipeline operator or storage provider; and

(v) The capacity and flow data from the FFSS Qualifying Pipeline or storage facility for the gas day prior to the Force Majeure Event until the gas day after the Force Majeure Event;

(c) To the best of its knowledge, how, why, and to what extent the Force Majeure Event actually and directly affected the FFSSR's ability to perform;

(d) The FFSSR's heat rate;

(e) The applicable nominations, and if applicable, no-notice delivered, on the FFSS Qualifying Pipeline from the gas day prior to the Force Majeure Event until the day after the Force Majeure Event; and

(f) ERCOT will have the right to request that the Generation Entity provide, or cause to be provided, any additional information ERCOT deems necessary, and the Generation Entity must provide such requested information to the extent reasonably within its possession or control. If the information is not in the possession of the Generation Entity (or its Affiliate) but may be in the possession of the FFSS Qualifying Pipeline operator or storage provider, the Generation Entity will exercise any contractual rights it has to request such information from the FFSS Qualifying Pipeline operator or storage provider, as applicable.

(24) Unless the agreement is a certified contract, if the relevant Firm Transportation Agreement and/or Firm Gas Storage Agreement does not ensure firmness in the manner required by the ERCOT Protocols, ERCOT shall revoke the award and claw back and/or withhold all of the FFSS Hourly Standby Fees for all of the days of the obligation period.

(25) For an FFSSR, a Force Majeure Event will be treated the same as any other cause for unavailability for the purposes of calculating the FFSSR's FFSS Hourly Rolling Equivalent Availability Factor and for paragraphs (9) through (15) above.

(26) It will constitute a material change under the ERCOT Protocols if a primary Generation Resource or any alternate Generation Resource that qualified to provide FFSS under paragraph (1)(c) above ceases to satisfy any of the requirements to qualify as an FFSSR under paragraph (1)(c) above (for example, but not limited to, if the Firm Transportation Agreement is terminated or if the FFSS Qualifying Pipeline no longer qualifies as an FFSS Qualifying Pipeline).

(a) The QSE of such Generation Resource will be required to notify ERCOT within two Business Days of such a material change.

(b) ERCOT may decertify a primary Generation Resource or alternate Generation Resource if such material change is, in ERCOT's sole opinion, an adverse change (for example, but not limited to, if a Firm Transportation Agreement is terminated and not replaced with a comparable, qualifying Firm Transportation Agreement).

ERCOT Impact Analysis Report

NPRR Number	1241	NPRR Title	Firm Fuel Supply Service (FFSS) Availability and Hourly Standby Fee
Impact Analysis Date	January 28, 2025		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1256	NPRR Title	Settlement of MRA of ESRs
Date of Decision	April 8, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $25K and $50K Project Duration: 3 to 5 months		
Proposed Effective Date	Upon system implementation; and upon system implementation of Nodal Protocol Revision Request (NPRR) 885, Must-Run Alternative (MRA) Details and Revisions Resulting from PUCT Project No. 46369, Rulemaking Relating to Reliability Must-Run Service		
Priority and Rank Assigned	Priority – 2027; Rank – 4800		
Nodal Protocol Sections Requiring Revision	6.6.6.7, MRA Standby Payment 6.6.6.9, MRA Payment for Deployment Event 6.6.6.10, MRA Variable Payment for Deployment		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This NPRR changes language in select provisions in Section 6, Adjustment Period and Real-Time Operations, related to Must-Run Alternatives (MRAs) primarily in grey-boxed language from NPRR885 in order to align the terminology for Energy Storage Resources (ESRs) for the single-model era and specify how Qualified Scheduling Entities (QSEs) representing ESR MRAs would be settled for the provision of MRA Service. The Settlement changes reflect that ESR MRAs would not have fuel costs, but would have costs associated with charging.		
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		

Board Report

	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	NPRR885 introduced the rules for compensating Resources under an MRA Agreement. Specifically, NPRR885 focused on the MRA Settlement of Generation Resources, Demand response, and other generation. With this NPRR, ERCOT provides specific language needed to describe the Settlement approach for an ESR MRA.
PRS Decision	On 11/14/24, PRS voted unanimously to table NPRR1256 and refer the issue to WMS. All Market Segments participated in the vote. On 2/12/25, PRS voted unanimously to recommend approval of NPRR1256 as amended by the 1/27/25 ERCOT comments. All Market Segments participated in the vote. On 3/12/25, PRS voted unanimously to endorse and forward to TAC the 2/12/25 PRS Report and 10/14/24 Impact Analysis for NPRR1256 with a recommended priority of 2027 and rank of 4800. All Market Segments participated in the vote.
Summary of PRS Discussion	On 11/14/24, ERCOT Staff provided an overview of NPRR1256. On 2/12/25, there was no discussion. On 3/12/25, participants reviewed the Impact Analysis for NPRR1256 and discussed the appropriate priority and rank.
TAC Decision	On 3/26/25, TAC voted unanimously to recommend approval of NPRR1256 as recommended by PRS in the 3/12/25 PRS Report as revised by TAC. All Market Segments participated in the vote.
Summary of TAC Discussion	On 3/26/25, TAC reviewed the items below and proposed desktop edits to correct a parameter name within Section 6.6.6.7.
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

Board Report

	☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 4/8/25, the ERCOT Board voted unanimously to recommend approval of NPRR1256 as recommended by TAC in the 3/26/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1256 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1256.
ERCOT Opinion	ERCOT supports approval of NPRR1256.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1256 and believes the market impact for NPRR1256 clarifies the Settlement treatment of ESR MRAs.

Sponsor	
Name	Ino Gonzalez / Magie Shanks
E-mail Address	ino.gonzalez@ercot.com / magie.shanks@ercot.com
Company	ERCOT
Phone Number	512-248- 3954 / 512-248-6472
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
E-Mail Address	Cory.phillips@ercot.com
Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**

WMS 120524	Requested PRS continue to table NPRR1256 for further review by the Wholesale Market Working Group (WMWG)
ERCOT 012725	Provided revisions to clarify how ERCOT ensures MRA ESRs meet the awarded capacity and energy requirements
WMS 020625	Endorsed NPRR1256 as amended by the 1/27/25 ERCOT comments

Market Rules Notes

None

Proposed Protocol Language Revision

[NPRR885: Insert Section 6.6.6.7 below upon system implementation:]

6.6.6.7 MRA Standby Payment

(1) The Standby Payment for MRA Service is paid to each QSE representing an MRA for each MRA Contracted Hour under performance requirements set forth in Section 22, Attachment N, Standard Form Must-Run Alternative Agreement, the MRA Request for Proposal (RFP), and the Protocols.

(2) The standby payment to each QSE representing a Generation Resource ~~or Energy Storage Resource (ESR)~~ MRA registered is calculated as follows for each hour:

$$MRASBAMT_{q,r,h} = (-1) * MRASBPR_{q,r,m} * MRACCAP_{q,r,m} * MRA\cancel{GR}CRF_{q,r,m} * MRAARF_{q,r,m}$$

Where:

$$MRA\cancel{GR}CRF_{q,r,m} = (MRATCAP_{q,r,m} + MRATCAPA_{q,r,m}) / MRACCAP_{q,r,m}$$

(3) The standby payment to each QSE representing an Energy Storage Resource (ESR) MRA registered is calculated as follows for each hour:

$$MRASBAMT_{q,r,h} = (-1) * MRASBPR_{q,r,m} * MRACCAP_{q,r,m} * MRACRF_{q,r,m} * MRAARF_{q,r,m} * MRAESRERF_{q,r,h}$$

Where:

$$MRACRF_{q,r,m} = (MRATCAP_{q,r,m} + MRATCAPA_{q,r,m}) / MRACCAP_{q,r,m}$$

And,

$\underline{MRAESRERF_{q,\,r,\,h} = Min\,[1, (MRAHOSOC_{q,\,r,\,b,\,m}) / (MRACCAP_{q,\,r,\,m} * MRABHO_{q,\,r,\,b,\,m})]}$

(~~3~~4) The standby payment to each QSE representing an Other Generation MRA or Demand Response MRA is calculated as follows for each hour:

$$MRASBAMT_{q,\,r,\,h} = (-1) * MRASBPR_{q,\,r,\,m} * MRACCAP_{q,\,r,\,m} * MRAEPRF_{q,\,r,\,m} * MRAARF_{q,\,r,\,m}$$

(~~4~~5) The MRA Capacity Availability Reduction Factor (MRAARF) is calculated as:

For initial Settlement

$$MRAARF_{q,\,r,\,m} = 1$$

For all other resettlements

If $MRACMAF_{q,\,r,\,m} \geq 95\% * MRATA_{q,\,r,\,m}$

$$MRAARF_{q,\,r,\,m} = 1$$

If $85\% * MRATA_{q,\,r,\,m} \leq MRACMAF_{q,\,r,m} < 95\% * MRATA_{q,\,r,\,m}$

$$MRAARF_{q,\,r,\,m} = MRACMAF_{q,\,r,\,m}$$

If $MRACMAF_{q,\,r,\,m} < 85\% * MRATA_{q,\,r,\,m}$

$$MRAARF_{q,\,r,\,m} = (MRACMAF_{q,\,r,\,m})^2$$

Where:

For an MRA registered as a Generation Resource or ESR,

$$MRACMAF_{q,\,r,\,m} = \sum_{h} (MRAMAH_{q,\,r,\,h}) / (MH_{q,\,r,\,m})$$

And,

For an MRA not registered as a Generation Resource or ESR, the availability factor is calculated pursuant to Section 3.14.4.6.4, MRA Availability Measurement and Verification.

The above variables are defined as follows:

Variable	Unit	Definition
$MRASBAMT_{q,\,r,\,h}$	$	*Must-Run Alternative Standby Amount per QSE per Resource by hour*—The hourly standby payment for MRA *r* represented by QSE *q*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.

MRASBPR $_{q, r, m}$	$/MW per hour	*Must-Run Alternative Standby Price per QSE per Resource per MW per hour*—The hourly standby price per MW for MRA *r* represented by QSE *q*, for the month *m*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
MRAEPRF $_{q, r, m}$	None	*Must-Run Alternative Event Performance Reduction Factor per QSE per Resource*—The Event Performance Reduction Factor of the MRA *r* represented by QSE *q*, for each hour of the month m, as calculated per Section 3.14.4.6.5, MRA Event Performance Measurement and Verification. If the MRAEPRF for the month is not available then the most recent MRAEPRF prior to month of the Operating Day shall be used. If no previous MRAEPRF is available then MRAEPRF shall be set to 1. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRA~~GR~~CRF $_{q, r, m}$	None	*Must-Run Alternative Generation Resource or ESR Capacity Reduction Factor per QSE per Resource per month* —The capacity reduction factor of the Generation Resource or ESR MRA *r* represented by QSE *q*, for each hour of the month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAESRERF $_{q, r, h}$	None	*Must-Run Alternative Energy Storage Resource Energy Reduction Factor per QSE per Resource per hour*—The energy reduction factor of the MRA ESR *r* represented by QSE *q*, for each hour *h* of the obligation block(s) of the month.
MRAHOSOC $_{q, r, b, m}$	MWh	*Must-Run Alternative Hour of Obligation Block State of Charge per QSE per Resource*—The most recent telemetered state-of-charge prior to or at the start of the obligation block *b* for MRA ESR *r* represented by QSE *q* as specified in the MRA Agreement, for the MRA Contracted Month *m*.
MRABHO $_{q, r, b, m}$	Hours	*Must-Run Alternative Hours of Obligation Block per QSE per Resource*—The number of hours per block *b* of hours of obligation for a registered MRA ESR *r*, represented by QSE *q*, as specified in the MRA Agreement, for the MRA Contracted Month *m*.
MRACCAP $_{q, r, m}$	MW	*Must-Run Alternative Contract Capacity per QSE per Resource*—The capacity of MRA *r* represented by QSE *q* as specified in the MRA Agreement, for the MRA Contracted Month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAARF $_{q, r, m}$	None	*Must-Run Alternative Availability Reduction Factor per QSE per Resource*—The availability reduction factor of MRA *r* represented by QSE *q*, for each hour of the MRA Contracted Month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRATCAPA $_{q, r, m}$	MW	*Must-Run Alternative Testing Capacity Adjustment per month*—The testing capacity adjustment factor of an MRA *r* represented by QSE *q*, for each hour of the MRA Contracted Month *m*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRATCAP $_{q, r, m}$	MW	*Must-Run Alternative Testing Capacity per month*—The testing capacity value of MRA *r* represented by QSE *q*, for each hour of the MRA Contracted Month *m*. If the MRATCAP for the month is not available then the most recent MRATCAP prior to month of the Operating Day shall be used. If no previous MRATCAP is available, then MRATCAP shall be set to MRACCAP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
MRATA $_{q, r, m}$	None	*Must-Run Alternative Target Availability per QSE per Resource per Month*—The monthly Target Availability of MRA *r* represented by QSE *q*, as specified in the MRA Agreement and divided by 100 to convert a percentage to a fraction. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.

MRACMAF $_{q, r, m}$	None	*Must-Run Alternative Calculated Monthly Availability Factor per QSE per Resource*—The calculated monthly availability factor of MRA *r* represented by QSE *q*. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MRAMAH $_{q, r, h}$	Hour	*Number of Available Hours in the Month per QSE per Resource*— For an MRA registered as a Generation Resource or ESR, the total number of hours in the month when the MRA *r* represented by QSE *q* was available for the MRA Contracted Hours if the MRA's Availability Plan and telemetry both indicate availability for that hour. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
MH $_{q, r, m}$	Hour	*Number of Total MRA Contracted Hours in the Month per QSE per Resource*— The total number of MRA Contracted Hours in the month for the MRA *r* represented by QSE *q* as indicated in the MRA Agreement. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
h	None	A MRA Contracted Hour under the MRA Agreement for the MRA Contracted month.
q	None	A QSE.
r	None	An MRA.
m	None	An MRA Contracted Month under the MRA Agreement.
b	None	An obligation block under the MRA Agreement.

(6~~5~~) The total of the Standby Payments for all MRAs represented by the QSE for a given hour is calculated as follows:

$$\text{MRASBAMTQSETOT}_{q} = \sum_{r} \text{MRASBAMT}_{q, r, h}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRASBAMTQSETOT $_q$	$	*Must-Run Alternative Standby Amount Total per QSE per hour* — The total of the Standby Payments for all MRAs represented by the QSE *q* for the hour.
MRASBAMT $_{q, r, h}$	$	*Must-Run Alternative Standby Amount per QSE per Resource by hour* — The hourly standby payment amount for MRA *r* represented by QSE *q*, for the hour *h*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Train.
q	None	A QSE.
r	None	An MRA.
h	None	An MRA Contracted Hour under the MRA Agreement for the calendar month.

(7~~6~~) The total of the Standby Payments for a given hour is calculated as follows:

$$\text{MRASBAMTTOT} = \sum_{q} \text{MRASBAMTQSETOT}_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
MRASBAMTTOT	$	*Must-Run Alternative Standby Amount Total* —The total of the Standby Payments to all QSEs q for all MRAs for the hour.
$\text{MRASBAMTQSETOT}_{q}$	$	*Must-Run Alternative Standby Amount Total per QSE per hour* —The total of the Standby Payments for all MRAs represented by the QSE q for the hour.
q	None	A QSE.

[NPRR885: Insert Section 6.6.6.9 below upon system implementation:]

6.6.6.9 MRA Payment for Deployment Event

(1) The deployment event payment to each QSE representing a Generation Resource MRA:

$$\text{MRADEAMT}_{q,\,r,\,h} = (-1) * \text{Max}\{\text{EDPRICE}_{q,\,r,\,m},\ (\text{FIP} + \text{MRACEFA}_{q,\,r}) * \text{MRAPSUFQ}_{q,\,r}\} * \text{MRAFLAG}_{q,\,r,\,h} / \text{MRAH}_{q,\,r}$$

<u>(2) The deployment event payment to each QSE representing an ESR MRA:</u>

$$\underline{\text{MRADEAMT}_{q,\,r,\,h} = (-1) * (\text{EDPRICE}_{q,\,r,\,m}) * \text{MRAFLAG}_{q,\,r,\,h} / \text{MRAH}_{q,\,r}}$$

(<u>3</u>~~2~~) The deployment event payment to each QSE representing a Demand Response MRA or Other Generation MRA:

$$\text{MRADEAMT}_{q,\,r,\,h} = (-1) * \text{Max}\{\text{EDPRICE}_{q,\,r},\ (\text{FIP} + \text{MRACEFA}_{q,\,r}) * \text{MRAPSUFQ}_{q,\,r}\} * \text{MRAEPRF}_{q,\,r,\,m} / \text{MRAH}_{q,\,r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$\text{MRADEAMT}_{q,\,r,\,h}$	$	*Must-Run Alternative Deployment Event Amount per QSE per Resource by hour*—The deployment event payment to QSE q for MRA r, for the MRA Contracted Hour h. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
FIP	$/MMBtu	*Fuel Index Price*—The FIP for the Operating Day.
$\text{EDPRICE}_{q,\,r}$	$	*Event Deployment Price per QSE per Resource*—The event deployment price to QSE q for MRA r, as specified in the MRA Agreement. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.
$\text{MRAEPRF}_{q,\,r,\,m}$	None	*Must-Run Alternative Event Performance Reduction Factor per QSE per Resource* —The event performance reduction factor of the MRA r represented by QSE q, for each hour of the month m, as calculated per Section 3.14.4.6.5, MRA Event Performance Measurement and Verification. If the MRAEPRF for the month is not available then the most recent MRAEPRF prior to the month of the Operating Day shall be used. If no previous MRAEPRF is available then MRAEPRF shall be set to 1. Where for a Combined Cycle Train, the Resource r is the Combined Cycle Train.