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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 February 4, 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 Request (NOGRR), Other Binding Documents Revision Request (OBDRR), Planning Guide Revision Requests (PGRRs) and System Change Request (SCR)):

- NPRR1243, Revision to Requirements for Notice and Release of Protected Information or ECEII to Certain Governmental Authorities;
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era;
- NPRR1250, RPS Mandatory Program Termination;
- NPRR1251, Updated FFSS Fuel Replacement Costs Recovery Process;
- NPRR1252, Pre-notice for Sharing of Some Information, Addition of Research and Innovation Partner, Clarifying Notice Requirements;
- NPRR1253, Incorporate ESR Charging Load Information into ICCP;
- NPRR1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response;
- NPRR1258, TSP Performance Monitoring Update;
- NPRR1259, Update Section 15 Level Response Language;
- NPRR1260, Corrections for CLR Requirements Inadvertently Removed;
- NPRR1261, Operational Flexibility for CRR Auction Transaction Limits;

- NOGRR268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era;
- NOGRR271, Related to NPRR1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response;
- OBDRR052, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era;
- PGRR117, Addition of Resiliency Assessment and Criteria to Reflect PUCT Rule Changes;
- PGRR118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era; and
- SCR828, Increase the Number of Resource Certificates Permitted for an Email Domain in RIOO.

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.

Dated: February 10, 2025

Respectfully submitted,

/s/ Brandt Rydell

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ATTORNEYS FOR ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

Board Report

NPRR Number	1243	NPRR Title	Revision to Requirements for Notice and Release of Protected Information or ECEII to Certain Governmental Authorities
Date of Decision		February 4, 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		1.3.4, Protecting Disclosures to the PUCT, CFTC, Governmental Cybersecurity Oversight Agencies, and Other Governmental Authorities 1.3.5, Notice Before Permitted Disclosure 1.3.6, Exceptions	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Protocol Revision Request (NPRR) revises requirements regarding notice and disclosure of Protected Information and ERCOT Critical Energy Infrastructure Information (ECEII). First, this NPRR proposes that notice before disclosure is not required when ERCOT, as the Receiving Party, provides Protected Information or ECEII to the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), the NERC Regional Entity, or a Governmental Cybersecurity Oversight Agency, and removes the requirement that disclosure of Protected Information or ECEII under paragraph (1)(j) of Section 1.3.6, Exceptions, is permissible only if necessary to comply with any applicable NERC or NERC Regional Entity requirement. Additionally, this NPRR adds FERC to the list of explicitly designated entities to which Protected Information and ECEII can be provided under paragraph (1)(j) of Section 1.3.6. This NPRR also adds FERC to the list of explicitly designated entities in paragraphs (4) and (5) of	

Board Report

	Section 1.3.4, Protecting Disclosures to the PUCT, CFTC, Governmental Cybersecurity Oversight Agencies, and Other Governmental Authorities, to which disclosures of Protected Information and ECEII do not trigger a requirement for the Receiving Party or Creating Party to seek a protective order as a condition for such disclosure.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	Under the current Protocols, if ERCOT, as the Receiving Party, is required to disclose Protected Information or ECEII to the PUCT, Reliability Monitor, or Independent Market Monitor (IMM), or if ERCOT, as the Receiving Party, must disclose Protected Information or ECEII to the Commodity Futures Trading Commission (CFTC), ERCOT does not have to first provide notice under paragraph (1) of Section 1.3.5, Notice Before Permitted Disclosure, that it will be disclosing that data. This is administratively efficient as the PUCT, Reliability Monitor, IMM, and CFTC all have business needs for ERCOT-held Protected Information or ECEII to carry out their regulatory obligations. ERCOT has similar obligations to provide Protected Information and ECEII to FERC, NERC, the NERC Regional Entity, and Governmental Cybersecurity Oversight Agencies, which may likewise need that data to carry out their regulatory obligations. Consequently, providing notice to Market Participants each time before ERCOT, as the Receiving Party, discloses such information to FERC, NERC, the NERC Regional Entity, or a Governmental Cybersecurity Oversight Agency is unnecessary.

Board Report

	Under the current Protocols, ERCOT can disclose Protected Information and ECEII to FERC, NERC, and the NERC Regional Entity if required to do so by any law, regulation, or order, or by the Protocols, and ERCOT can disclose Protected Information and ECEII to NERC and the NERC Regional Entity if required for compliance with any applicable NERC or NERC Regional Entity requirement. Requiring that each disclosure be explicitly linked to a specific law, regulation, order, or NERC or NERC Regional Entity requirement is unnecessary, given the broad authority of these entities to investigate matters relating to the reliability of the bulk-power system. Leaving this language in paragraph (1)(j) of Section 1.3.6 may mislead some by suggesting that these entities have only limited authority to obtain information. Furthermore, explicitly recognizing FERC as one of the Governmental Authorities to which Protected Information or ECEII may be provided aligns with other provisions that explicitly identify other Governmental Authorities that are more likely to need such information. Finally, revising Section 1.3.4 to add FERC to the list of Governmental Authorities that do not trigger the requirement for the Receiving Party or Creating Party to seek a protective order before disclosing Protected Information and ECEII is appropriate because FERC (like the PUCT and CFTC) is not required to enter a protective order before exercising its investigative authority.
PRS Decision	On 8/8/24, PRS voted unanimously to table NPRR1243. All Market Segments participated in the vote. On 11/14/24, PRS voted unanimously to recommend approval of NPRR1243 as amended by the 10/14/24 Oncor comments. All Market Segments participated in the vote. On 12/12/24, PRS voted unanimously to endorse and forward to TAC the 11/14/24 PRS Report and 7/24/24 Impact Analysis for NPRR1243. All Market Segments participated in the vote.
Summary of PRS Discussion	On 8/8/24, ERCOT Staff presented NPRR1243. Some participants expressed concern for the inability to prepare a Market Notice when confidential information is provided to federal agencies and requested additional time to review the language. On 11/14/24, participants reviewed the 10/14/24 Oncor comments. On 12/12/24, participants noted the 7/24/24 Impact Analysis.
TAC Decision	On 1/22/25, TAC voted unanimously to recommend approval of NPRR1243 as recommended by PRS in the 12/12/24 PRS Report. All Market Segments participated in the vote.

Board Report

Summary of TAC Discussion	On 1/22/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed – with the exception of the IMM Opinion which was not available for TAC review. ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 2/4/25, the ERCOT Board voted unanimously to recommend approval of NPRR1243 as recommended by TAC in the 1/22/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1243 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 NPRR1243.
ERCOT Opinion	ERCOT supports approval of NPRR1243.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1243 and believes that it enhances administrative efficiency by updating and refining pre-disclosure obligations for certain disclosures of Protected Information or ECEII and revising a portion of the list of circumstances in which disclosure is permissible.

Sponsor	
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Board Report

Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
Reliant Energy 081424	Restored the requirement for ERCOT to provide notice to Market Participants (i.e. the Disclosing Party) before ERCOT discloses Protected Information or ECEII belonging to that Market Participant to FERC, NERC, the NERC Regional Entity, the CFTC, or a Governmental Cybersecurity Oversight Agency; removed the requirement for ERCOT to obtain a protective order for disclosures of Protected Information or ECEII to FERC
Reliant Energy 071924	Restored the exclusion to remove the requirement for ERCOT to provide notice to Market Participants for disclosures of ERCOT ECEII or protected information to CFTC to ensure ERCOT remains compliant with CFTC orders
Oncor 101424	Proposed that the existing language remain in effect; added a requirement that ERCOT to publicly post and maintain on its website the categories of Protected Information/ECEII it is disclosing to FERC, NERC, and TRE in lieu of individually notifying the Disclosing Parties that provided this Protected Information/ECEII to ERCOT; restored the requirement for ERCOT only to disclose PI/ECEII to FERC, NERC, or TRE if the disclosure is required for adherence to a regulatory requirement; and clarified that "applicable regulatory requirement" means requirements imposed by FERC pursuant to the Federal Power Act

Market Rules Notes

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

- NPRR1252, Pre-notice for Sharing of Some Information, Addition of Research and Innovation Partner, Clarifying Notice Requirements
  - Section 1.3.5
  - Section 1.3.6

Board Report

Proposed Protocol Language Revision

1.3.4 Protecting Disclosures to the PUCT, FERC, CFTC, Governmental Cybersecurity Oversight Agencies, and Other Governmental Authorities

(1) Any disclosure that a Receiving Party makes to the PUCT must be made under applicable PUCT rules. For any disclosure of Protected Information or ECEII to the PUCT outside the scope of subsection (e) of P.U.C. SUBST. R. 25.362, Electric Reliability Council of Texas (ERCOT) Governance, the Receiving Party must file that Protected Information or ECEII as confidential pursuant to subsection (d) of P.U.C. PROC. R. 22.71, Filing of Pleadings, Documents, and Other Materials.

(2) For any disclosure of Protected Information to the Commodity Futures Trading Commission (CFTC) pursuant to a request made under the CFTC's authority in accordance with the Commodity Exchange Act and the CFTC's regulations, ERCOT, as the Receiving Party, shall timely submit to the CFTC a written request for confidential treatment of the Protected Information in accordance with the applicable provisions of the Commodity Exchange Act and CFTC regulations.

(3) Before making a disclosure of Protected Information involving a Cybersecurity Incident to a Governmental Cybersecurity Oversight Agency or delegated entity for the purpose of ensuring the safety and/or security of the ERCOT System or ERCOT's ability to perform functions of an independent organization under the Public Utility Regulatory Act (PURA), ERCOT, as the Receiving Party, will obtain adequate assurance from such Governmental Cybersecurity Oversight Agency that it will maintain the confidentiality of Protected Information.

(4) Before making a disclosure under order of a Governmental Authority other than the PUCT, the Federal Energy Regulatory Commission (FERC), and the CFTC, the Receiving Party or Creating Party shall seek a protective order from such Governmental Authority to protect the confidentiality of Protected Information or ECEII.

(5) Before making a disclosure under order of a Governmental Authority other than the PUCT, FERC, CFTC, or a Governmental Cybersecurity Oversight Agency to ensure the safety and/or security of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under PURA, the Receiving Party shall seek a protective order from such Governmental Authority to protect the confidentiality of Protected Information.

(6) Nothing in this Section authorizes any disclosure of Protected Information or ECEII; this Section merely creates requirements on disclosures that are authorized under other sections of these Protocols.

1.3.5 Notice Before Permitted Disclosure

(1) Before making any disclosure under Section 1.3.6, Exceptions, the Receiving Party shall promptly notify the Disclosing Party in writing and, with the exception of information disclosed pursuant to paragraph (3) of Section 1.3.6, shall assert confidentiality and take reasonable steps to cooperate with the Disclosing Party in seeking to protect the Protected Information or ECEII from disclosure by confidentiality agreement, protective order, aggregation of information, or other reasonable measures. Notwithstanding the foregoing, ERCOT is not required to provide notice to the Disclosing Party of disclosures by ERCOT made under items (1)(b), ~~(1)(i), (1)(l)~~ (1)(l), ~~(1)(m),~~ or (1)(n) of Section 1.3.6.

(2) If the Disclosing Party is not also the Creating Party, upon receipt of the notice required by paragraph (1) above, the Disclosing Party shall promptly notify the Creating Party, unless, after making reasonable efforts, the Disclosing Party is unable to identify the Creating Party.

(3) Notwithstanding any other provision in these Protocols, ERCOT may provide notice of any one or more categories of Protected Information and ECEII it discloses as the Receiving Party under paragraph (1)(j) of Section 1.3.6 by publicly posting and maintaining on the ERCOT website a list of such categories in lieu of individually notifying each Disclosing Party.

(a) Before disclosing Protected Information or ECEII under a new category that ERCOT proposes to add to the list, ERCOT will issue a Market Notice describing the new category of Protected Information or ECEII, identifying the intended date of disclosure, and providing notice that the list will be updated.

(b) The Market Notice will be issued as far in advance of the disclosure as practicable under the circumstances or at least 10 Business Days before the disclosure, whichever is shorter.

1.3.6 Exceptions

(1) The Receiving Party or Creating Party may, without violating Section 1.3, Confidentiality, disclose Protected Information or ECEII:

(a) To governmental officials, Market Participants, the public, or others as required by any law, regulation, or order, or by these Protocols, but any Receiving Party or Creating Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII by protective order, by aggregating information, or otherwise if reasonably possible; or

(b) If ERCOT is the Receiving Party or Creating Party and disclosure to the PUCT, Reliability Monitor or IMM of the Protected Information or ECEII is required by ERCOT pursuant to applicable Protocol, law, regulation, or order; or

Commented [BA1]: Please note NPRR1252 also proposes revisions to this section.

Commented [BA2]: Please note NPRR1252 also proposes revisions to this section.

(c) For Protected Information, if the Disclosing Party has given its prior written consent to the disclosure, which consent may be given or withheld in Disclosing Party's sole discretion; or

(d) For Protected Information, if the Protected Information, before it is furnished to the Receiving Party, has been disclosed to the public through lawful means; or

(e) For Protected Information, if the Protected Information, after it is furnished to the Receiving Party, is disclosed to the public other than as a result of a breach by the Receiving Party of its obligations under Section 1.3; or

(f) If reasonably deemed by the disclosing Receiving Party to be required to be disclosed in connection with a dispute between the Receiving Party and the Disclosing Party, but the disclosing Receiving Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII by protective order, by aggregating information, or otherwise if reasonably possible; or

(g) To a TSP or DSP engaged in the ERCOT Transmission Grid or Distribution System planning and operating activities, provided that the TSP or DSP has executed a confidentiality agreement with ERCOT with requirements substantially similar to those in Section 1.3. ERCOT shall post on the ERCOT website a list of all TSPs and DSPs that have confidentiality agreements in effect with ERCOT; or

(h) For Protected Information, to a vendor or prospective vendor of goods and services to ERCOT or a TDSP, so long as such vendor or prospective vendor:

(i) Is not a Market Participant, except that ERCOT or the TDSP may disclose Protected Information to a vendor or prospective vendor that is also an Independent Market Information System Registered Entity (IMRE) to the extent appropriate for the vendor to carry out its responsibilities in such capacity or for the prospective vendor to engage in commercial discussions; and

(ii) Has executed a confidentiality agreement with requirements at least as restrictive as those in Section 1.3; or

(i) For ECEII, to a vendor or prospective vendor of goods and services, so long as such vendor or prospective vendor has executed a confidentiality agreement with requirements at least as restrictive as those in Section 1.3; or

(j) To FERC, the North American Electric Reliability Corporation (NERC), or the NERC Regional Entity if requested under the authority of the Federal Power Act Section 215 ~~if required for compliance with any applicable NERC or NERC Regional Entity requirement~~, but any Receiving Party or Creating Party must make reasonable efforts to restrict public access to the disclosed Protected Information or ECEII ~~as reasonably possible~~. This exception does not limit

FERC's, NERC's, or the NERC Regional Entity's access to Protected Information or ECEII as it existed on September 1, 2024; or

(k) To ERCOT and its consultants, the IMM, the Reliability Monitor, and members of task forces and working groups of ERCOT, if engaged in performing analysis of abnormal system conditions, disturbances, unusual events, and abnormal system performance, or engaged in tasks involving ECEII for support of the ERCOT Transmission Grid. Notwithstanding the foregoing sentence, task forces and working groups may not receive Ancillary Service Offer prices or other competitively sensitive price or cost information before expiration of its status as Protected Information, and each member of a task force or working group shall execute a confidentiality agreement with requirements substantially similar to those in Section 1.3, prior to receiving any Protected Information or ECEII. Data to be disclosed under this exception to task forces and working groups must be limited to clearly defined periods surrounding the relevant conditions, events, or performance under review and must be limited in scope to information pertinent to the condition or events under review and may include the following:

(i) QSE Ancillary Service awards and deployments, in aggregate and by type of Resource;

(ii) Resource facility availability status, including the status of switching devices, auxiliary loads, and mechanical systems that had a material impact on Resource facility availability or an adverse impact on the transmission system operation;

(iii) Individual Resource information including Base Points, maximum/minimum generating capability, droop setting, real power output, and reactive output;

(iv) Resource protective device settings and status;

(v) Data from COPs;

(vi) Resource Outage schedule information; and

(vii) BSS test results and ERCOT's Black Start plan, including individual Black Start Resource start-up procedures, cranking paths, and individual TSP Black Start plans;

(l) To the CFTC if requested from ERCOT by the CFTC as part of an investigation or regulatory inquiry authorized pursuant to the Commodity Exchange Act and the CFTC's regulations or if required to be submitted to the CFTC pursuant to any other law, provided that ERCOT, as the Receiving Party or Creating Party, must timely submit a written request for confidential treatment in accordance with the CFTC's regulations or other applicable law;

(m) To a Governmental Cybersecurity Oversight Agency regarding a Cybersecurity Incident, if ERCOT is the Receiving Party, and disclosure of Protected Information is made to a Governmental Cybersecurity Oversight Agency or delegated entity for the purpose of ensuring the safety and/or security of the ERCOT System or ERCOT's ability to perform the functions of an independent organization under PURA; or

(n) Incidentally as part of a tour of the ERCOT control room provided to persons determined by ERCOT to be eligible to participate in the tour. Prior to accessing the ERCOT control room, such persons must sign a nondisclosure agreement required by ERCOT and comply with the screening and other requirements provided in a policy adopted by ERCOT security. The policy will include a prohibition against taking photographs or recordings of Protected Information or ECEII. This subsection does not apply to a person who is a director, officer, employee, agent, representative, contractor, or consultant of a Market Participant that is registered with ERCOT as one or more of the following registration types: Resource Entity, QSE, LSE, or CRR Account Holder.

(2) Protected Information may not be disclosed to other Market Participants prior to ten days following the Operating Day under review, except as permitted in paragraph (1)(n) above.

(3) ERCOT may disclose, and may authorize a Receiving Party or Creating Party to disclose, ECEII to the public or to any person under the provisions of this paragraph, except for ECEII otherwise protected from disclosure pursuant to law, regulation, or order.

(a) ERCOT may propose to disclose ECEII that is not otherwise protected from disclosure pursuant to law, regulation, or order. Any Receiving Party or Creating Party other than ERCOT may request ERCOT authorization to disclose such ECEII.

(i) ERCOT may propose to disclose ECEII that is not otherwise protected from disclosure pursuant to law, regulation, or order if it determines that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure. ERCOT shall issue a Market Notice regarding ERCOT's intent to disclose the ECEII, subject to objection as further provided in paragraph (c) below.

(ii) A request by a Receiving Party or Creating Party other than ERCOT for authorization to disclose ECEII shall be submitted by e-mail to ERCOT's General Counsel. If the ECEII is not otherwise protected from disclosure pursuant to law, regulation, or order, and ERCOT determines that the public benefit of the proposed disclosure of ECEII outweighs the potential harm resulting from the disclosure, ERCOT shall issue a Market Notice authorizing the ECEII to be disclosed, subject to objection as further provided in paragraph (c) below. ERCOT shall make such a

determination no later than five Business Days following the date it receives the request.

(b) The Market Notice issued pursuant to paragraph (a)(i) or (ii) above shall identify the ECEII to be disclosed; the party requesting the disclosure; the public benefit justifying the proposed disclosure; the date on which the information may be disclosed, which shall be no sooner than five Business Days following the date of the Market Notice; and, if the proposed disclosure is not to the public, the persons to whom ECEII would be disclosed. The authorization shall be effective unless a Market Participant submits an objection pursuant to paragraph (c) below.

(c) Any Market Participant may submit written objections to the proposed disclosure. Such objections shall be submitted by e-mail to ERCOT's General Counsel no later than the end of the fourth Business Day following the issuance of the Market Notice described in paragraph (b) above. Failure to object to the proposed allowance of ECEII disclosure pursuant to this paragraph shall constitute a waiver of any such objection for all purposes. ERCOT shall provide notice of the objection to the party requesting authorization to disclose ECEII no later than the end of the Business Day following receipt of the objection. The party requesting authorization to disclose ECEII shall not disclose the ECEII if it has been notified of any objection pursuant to this paragraph unless and until ERCOT issues a second Market Notice authorizing disclosure, as provided in paragraph (d) below.

(d) If one or more objections to disclosure is submitted pursuant to paragraph (c) above, ERCOT shall issue a second Market Notice describing each such objection and stating whether the objection affects ERCOT's determination as to the proposed disclosure of ECEII. If ERCOT determines that the ECEII should still be disclosed notwithstanding these objections, the second Market Notice shall establish the date on which the ECEII may be disclosed, which shall be no sooner than the fifth Business Day following the issuance of the second Market Notice. ERCOT's determination in the second Market Notice is a final decision that may be challenged at the PUCT without using the processes described in Section 20, Alternative Dispute Resolution Procedure and Procedure for Return of Settlement Funds. If ERCOT authorizes a non-public disclosure of ECEII, the party disclosing the ECEII shall require each recipient of ECEII to enter into a nondisclosure agreement that includes the restrictions against disclosure described in Section 1.3.2, ERCOT Critical Energy Infrastructure Information, as a condition for obtaining the ECEII.

(e) Notwithstanding anything in this Section, ERCOT may disclose ECEII to any federal, state or local government official without issuing a Market Notice if ERCOT determines that such disclosure is necessary to facilitate the government official's public duties and that the delay associated with providing the Notice otherwise required by this paragraph (3) would impair that government official's ability to take action to address a public emergency. As soon as practicable, but no later than 24 hours following the disclosure:

(i) ERCOT shall provide Notice to the Disclosing Party and all Market Participants materially impacted by the disclosure; and

(ii) ERCOT shall issue a Market Notice describing the disclosure, unless ERCOT determines that such a Notice could jeopardize public safety or welfare, in which case no Notice is required.

(iii) Each Disclosing Party, other than ERCOT, shall provide Notice to each Creating Party whose information has been disclosed pursuant to this paragraph (e).

(f) Notwithstanding anything in this Section, any Receiving Party or Creating Party other than ERCOT may disclose ECEII to any federal, state or local government official without requesting prior authorization from ERCOT if the Receiving Party or Creating Party determines that such disclosure is necessary to facilitate the government official's public duties and that the delay associated with requesting prior ERCOT authorization as otherwise required by this paragraph (3) would impair that government official's ability to take action to address a public emergency.

(i) The Receiving Party or Creating Party shall provide Notice to ERCOT and all Market Participants materially impacted by the disclosure as soon as practicable, but no later than 24 hours following the disclosure.

(ii) ERCOT shall issue a Market Notice describing the disclosure as soon as practicable, but no later than 24 hours following receipt of notice from the Receiving Party or Creating Party, unless ERCOT determines that such a Notice could jeopardize public safety or welfare, in which case no Notice is required.

ERCOT Impact Analysis Report

NPRR Number	1243	NPRR Title	Revision to Requirements for Notice and Release of Protected Information or ECEII to Certain Governmental Authorities
Impact Analysis Date		July 24, 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	1246	NPRR Title	Energy Storage Resource Terminology Alignment for the Single-Model Era
Date of Decision		February 4, 2025	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		Upon system implementation of PR447, Real-Time Co-Optimization (RTC)	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		1.3.1.1, Items Considered Protected Information 1.3.1.2, Items Not Considered Protected Information 1.6.5, Interconnection of New or Existing Generation 2.1, Definitions 2.2, Acronyms and Abbreviations 3.1.1, Role of ERCOT 3.1.3.2, Resources 3.1.4.5, Notice of Forced Outage or Unavoidable Extension of Planned, Maintenance, or Rescheduled Outage Due to Unforeseen Events 3.1.5.1, ERCOT Evaluation of Planned Outage and Maintenance Outage of Transmission Facilities 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests 3.6.1, Load Resource Participation 3.8.5, Energy Storage Resources 3.10.1, Time Line for Network Operations Model Changes 3.10.3, CRR Network Model 3.10.6, Resource Entity Responsibilities 3.10.7.1.4. Transmission and Generation Resource Step-Up Transformers 3.10.7.2, Modeling of Resources and Transmission Loads 3.10.7.6, Use of Generic Transmission Constraints and Generic Transmission Limits 3.10.7.7, DC Tie Limits 3.14.1.9, Generation Resource Status Updates 3.14.4.1, Overview and Description of MRAs 3.14.4.5, Standards for Generation Resource MRAs	

	3.14.4.7, MRA Testing 3.17.1, Regulation Service 3.17.2, Responsive Reserve Service 3.17.3, Non-Spinning Reserve Service 3.17.4, ERCOT Contingency Reserve Service 3.18, Resource Limits in Providing Ancillary Service 3.22.1.2, Generation Resource Interconnection Assessment 3.22.1.3, Transmission Project Assessment 3.22.1.4, Annual SSR Review 3.22.2, Subsynchronous Resonance Vulnerability Assessment Criteria 3.22.3, Subsynchronous Resonance Monitoring 4.4.6.3, PTP Obligations with Links to an Open DAM Award Eligibility 4.4.7.1, Self-Arranged Ancillary Service Quantities 4.4.7.3, Ancillary Service Trades 4.4.9.3.3, Energy Offer Curve Cost Caps 6.5.1.1, ERCOT Control Area Authority 6.5.3, Equipment Operating Ratings and Limits 6.5.5.1, Changes in Resource Status 6.5.7.1.13, Data Inputs and Outputs for the Real-Time Sequence and SCED 6.5.7.4, Base Points 6.5.7.4.1, Updated Desired Set Points 6.5.7.6.2.2, Deployment of Responsive Reserve (RRS) 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service 6.5.7.8, Dispatch Procedures 6.5.8, Verbal Dispatch Instruction Confirmation 6.5.9.4, Energy Emergency Alert 6.5.9.4.2, EEA Levels 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment 6.6.5.2, Set Point Deviation Charge for Over Generation 6.6.5.2.1, Set Point Deviation Charge for Under Generation 6.6.5.4, Set Point Deviation Payment 6.6.7.1, Voltage Support Service Payments 6.6.9, Emergency Operations Settlement 8.1, QSE and Resource Performance Monitoring 8.1.1.1, Ancillary Service Qualification and Testing 8.1.1.2.1.7, ERCOT Contingency Reserve Service Qualification 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics 8.2, ERCOT Performance Monitoring 8.4, ERCOT Response to Market Non-Performance 9.17.1, Billing Determinant Data Elements

Board Report

	9.19.1, Default Uplift Invoices 10.2.2, TSP and DSP Metered Entities 10.3.2.1.6, Allocating EPS Metered Data to Generator Owners When It Is Net Load 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters 10.3.2.4, Reporting of Net Generation Capacity 11.5.2, Generation Meter Data Aggregation 11.5.2.1, Participant Specific Generation Data Posting/Availability 13.2.4, Seasonal Transmission Loss Factor Calculation 16.5, Registration of a Resource Entity 16.14, Termination of Access Privileges to Restricted Computer Systems and Control Systems 26.2, Securitization Default Charges Section 22, Attachment E, Notification of Suspension of Operations Section 22, Attachment H, Notification of Generation Resource Designation Section 22, Attachment L, Declaration of Private Use Network Net Generation Capacity Availability Section 22, Attachment N, Standard Form Must-Run Alternative Agreement Section 22, Attachment P, Methodology for Setting Maximum Shadow Prices for Network and Power Balance Constraints Section 23, Form I, Resource Entity Application for Registration
Related Documents Requiring Revision/Related Revision Requests	Nodal Operating Guide Revision Request (NOGRR) 268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era Other Binding Document Revision Request (OBDRR) 052, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era Planning Guide Revision Request (PGRR) 118, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
Revision Description	This Nodal Protocol Revision Request (NPRR) inserts terminology associated with Energy Storage Resources (ESRs) in the appropriate places throughout the Protocols, aligning provisions and requirements for ESRs with those already in place for Generation Resources and Controllable Load Resources. NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions, which was approved by the ERCOT Board of Directors at its August 11, 2020, meeting, included a blanket provision in paragraph (1) of Section 3.8.5, Energy Storage Resources, as follows:

Board Report

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

Board Report

PRS Decision	On 9/12/24, PRS voted unanimously to table NPRR1246. All Market Segments participated in the vote. On 10/17/24, PRS voted unanimously to recommend approval of NPRR1246 as amended by the 9/20/24 ERCOT comments. All Market Segments participated in the vote. On 11/14/24, PRS voted unanimously to endorse and forward to TAC the 10/17/24 PRS Report and 7/31/24 Impact Analysis for NPRR1246. All Market Segments participated in the vote.
Summary of PRS Discussion	On 9/12/24, ERCOT Staff provided an overview of NPRR1246. On 10/17/24, participants reviewed the 9/20/24 ERCOT comments and noted the recent ROS vote to recommend approval of the related NOGRR268 and PGRR118. On 11/14/24, there was no discussion.
TAC Decision	On 11/20/24, TAC voted unanimously to recommend approval of NPRR1246 as recommended by PRS in the 11/14/24 PRS Report. All Market Segments participated in the vote. On 1/22/25, TAC voted unanimously to recommend approval of NPRR1246 as recommended by TAC in the 11/20/24 TAC Report as amended by the 1/21/25 ERCOT comments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/20/24, there was no additional discussion beyond TAC review of the items below. On 1/22/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 12/3/24, the ERCOT Board voted unanimously to remand NPRR1246 to TAC.

Board Report

	On 2/4/25, the ERCOT Board voted unanimously to recommend approval of NPRR1246 as recommended by TAC in the 1/22/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1246 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 NPRR1246.
ERCOT Opinion	ERCOT supports approval of NPRR1246.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1246 and believes the market impact for NPRR1246 provides clarity and additional transparency for stakeholders on the applicable provisions and requirements associated with ESRs as the market transitions from the combo model to the single model as part of the RTC+B project.

Sponsor	
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Company	ERCOT
Phone Number	
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Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
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Comments Received	
Comment Author	**Comment Summary**
ROS 091024	Requested PRS table NPRR1246

Board Report

ERCOT 092024	Proposed additional clarifying edits based on stakeholder discussions
ERCOT 012125	Proposed additional edits to align with NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources

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:

- NPRR945, Net Metering Requirements (unboxed 1/31/25)
  - Section 10.3.2.3
- NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions (unboxed 9/27/24)
  - Section 3.8.5
  - Section 16.5
- NPRR1131, Controllable Load Resource Participation in Non-Spin (unboxed 8/23/24)
  - Section 6.5.7.6.2.3
- NPRR1058, Resource Offer Modernization (unboxed 8/23/24)
  - Section 6.6.9
- NPRR1183, ECEII Definition Clarification and Updates to Posting Rules for Certain Documents without ECEII (unboxed 12/12/24)
  - Section 3.14.1.9
- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources (incorporated 12/1/24)
  - Section 1.3.1.1
  - Section 3.6.1
  - Section 6.5.7.4
  - Section 6.5.7.6.2.3
  - Section 8.1.1.1
  - Section 9.19.1
  - Section 10.2.2
  - Section 10.3.2.3
  - Section 26.2
- NPRR1198, Congestion Mitigation Using Topology Reconfigurations (incorporated 8/1/24)
  - Section 6.5.1.1
- NPRR1216, Implementation of Emergency Pricing Program (incorporated 10/1/24)
  - Section 4.4.9.3.3

- NPRR1217, Remove VDI Requirement for Deployment and Recall of Load Resources and ERS Resources (incorporated 10/1/24)
  - Section 6.5.9.4.2
- NPRR1218, REC Program Changes Per P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program (unboxed 11/1/24)
  - Section 1.3.1.1
- NPRR1221, Related to NOGRR262, Provisions for Operator-Controlled Manual Load Shed (incorporated 12/1/24)
  - Section 6.5.9.4.2
- NPRR1225, Exclusion of Lubbock Load from Securitization Charges (incorporated 10/1/24)
  - Section 26.2
- NPRR1230, Methodology for Setting Transmission Shadow Price Caps for an IROL in SCED (unboxed 10/2/24)
  - Section 22, Attachment P
- NPRR1239, Access to Market Information (incorporated 2/1/25)
  - Section 6.5.7.1.13
  - Section 8.1
- NPRR1240, Access to Transmission Planning Information (incorporated 2/1/25)
  - Section 3.1.3.2
- NPRR1244, Related to NOGRR263, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities (incorporated 12/1/24)
  - Section 3.6.1
- NPRR1249, Publication of Shift Factors for All Active Transmission Constraints in the RTM (incorporated 2/1/25)
  - Section 6.5.7.1.13
- NPRR1254, Modeling Deadline for Initial Submission of Resource Registration Data (incorporated 2/1/25)
  - Section 3.10.1

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

- NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs
  - Section 6.6.3.6
- NPRR1226, Demand Response Monitor
  - Section 6.5.7.1.13
- NPRR1234, Interconnection Requirements for Large Loads and Modeling Standards for Loads 25 MW or Greater
  - 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

- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  - Section 3.18
  - Section 4.4.7.1
  - Section 4.4.7.3
- NPRR1255, Introduction of Mitigation of ESRs
  - Section 3.8.5
- NPRR1257, Limit on Amount of RRS a Resource can Provide Using Primary Frequency Response
  - Section 3.18
- NPRR1260, Corrections for CLR Requirements Inadvertently Removed
  - Section 3.17.2

Proposed Protocol Language Revision

1.3.1.1 Items Considered Protected Information

(1) Subject to the exclusions set out in Section 1.3.1.2, Items Not Considered Protected Information, and in Section 3.2.5, Publication of Resource and Load Information, "Protected Information" is information containing or revealing any of the following:

(a) Base Points, as calculated by ERCOT. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(b) Bids, offers, or pricing information identifiable to a specific Qualified Scheduling Entity (QSE) or Resource. The Protected Information status of part of this information shall expire 60 days after the applicable Operating Day, as follows:

(i) Ancillary Service Offers by Operating Hour for each Resource for all Ancillary Services submitted for the Day-Ahead Market (DAM) or any Supplemental Ancillary Services Market (SASM);

(ii) The quantity of Ancillary Service offered by Operating Hour for each Resource for all Ancillary Service submitted for the DAM or any SASM; and

(iii) Energy Offer Curve prices and quantities for each Settlement Interval by Resource. The Protected Information status of this information shall expire within seven days after the applicable Operating Day if required to

be posted as part of paragraph (5) of Section 3.2.5 and within two days after the applicable Operating Day if required to be posted as part of paragraph (7) of Section 3.2.5;

[NPRR1013 and NPRR1188: Replace applicable portions of paragraph (b) above with the following upon system implementation for NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1013:]

(b) Bids, offers, or pricing information identifiable to a specific Qualified Scheduling Entity (QSE) or Resource. The Protected Information status of part of this information shall expire 60 days after the applicable Operating Day, as follows:

(i) Ancillary Service Offers by Operating Hour or Security-Constrained Economic Dispatch (SCED) interval for each Resource for all Ancillary Services submitted for the Day-Ahead Market (DAM) or Real-Time Market (RTM);

(ii) The quantity of Ancillary Service offered by Operating Hour or SCED interval for each Resource for all Ancillary Service submitted for the DAM or RTM; and

(iii) The prices and quantities presented in a Resource's Energy Offer Curve or Energy Bid Curve by Operating Hour or SCED interval. The Protected Information status of this information shall expire within seven days after the applicable Operating Day if required to be posted as part of paragraph (5) of Section 3.2.5 and within two days after the applicable Operating Day if required to be posted as part of paragraph (7) of Section 3.2.5;

(c) Status of Resources, including Outages, limitations, or scheduled or metered Resource data. The Protected Information status of this information shall expire as follows:

(i) For each Forced Outage, Maintenance Outage, or Forced Derate of a Generation Resource or Energy Storage Resource (ESR) that occurs during or extends into an Operating Day, the Protected Information status of the following information shall expire three days after the applicable Operating Day:

(A) The name and unit code of the Resource affected;

(B) The Resource's fuel type;

(C) The type of Outage or derate;

(D) The start date/time and the planned and actual end date/time;

(E) The Resource's applicable Seasonal net maximum sustainable rating;

(F) The available and outaged MW during the Outage or derate; and

(G) The entry in the "nature of work" field in the Outage Scheduler and any other information concerning the cause of the Outage or derate;

(ii) For each Resource Outage or Forced Derate that occurs during, or that extends into, any time period in which ERCOT has declared an Energy Emergency Alert (EEA), ERCOT may immediately disclose the information identified in paragraph (i) above to a state Governmental Authority, the office of the Governor of Texas, the office of the Lieutenant Governor of Texas, or any member of the Texas Legislature, if requested; and

(iii) For all other information, the Protected Information status shall expire 60 days after the applicable Operating Day;

(d) Current Operating Plans (COPs). The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(e) Ancillary Service Trades, Energy Trades, and Capacity Trades identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 180 days after the applicable Operating Day;

(f) Ancillary Service Schedules identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

[NPRR1013: Replace paragraph (f) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(f) Ancillary Service awards identifiable to a specific QSE or Resource. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(g) Dispatch Instructions identifiable to a specific QSE or Resource, except for Reliability Unit Commitment (RUC) commitments and decommitments as provided in Section 5.5.3, Communication of RUC Commitments and Decommitments. The Protected Information status of this information shall expire 180 days after the applicable Operating Day;

(h) Raw and Adjusted Metered Load (AML) data (demand and energy) identifiable to:

(i) A specific QSE or Load Serving Entity (LSE). The Protected Information status of this information shall expire 180 days after the applicable Operating Day; or

(ii) A specific Customer or Electric Service Identifier (ESI ID);

(i) Wholesale Storage Load (WSL) data identifiable to a specific QSE. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(j) Settlement Statements and Invoices identifiable to a specific QSE. The Protected Information status of this information shall expire 180 days after the applicable Operating Day;

(k) Number of ESI IDs identifiable to a specific LSE. The Protected Information status of this information shall expire 365 days after the applicable Operating Day;

(l) Information related to generation interconnection requests, to the extent such information is not otherwise publicly available. The Protected Information status of certain generation interconnection request information expires as provided in Section 1.3.1.4, Expiration of Protected Information Status;

(m) Resource-specific costs, design and engineering data, including such data submitted in connection with a verifiable cost appeal;

(n) Congestion Revenue Right (CRR) credit limits, the identity of bidders in a CRR Auction, or other bidding information identifiable to a specific CRR Account Holder. The Protected Information status of this information shall expire as follows:

(i) The Protected Information status of the identities of CRR bidders that become CRR Owners and the number and type of CRRs that they each own shall expire at the end of the CRR Auction in which the CRRs were first sold; and

(ii) The Protected Information status of all other CRR information identified above in item (n) shall expire six months after the end of the year in which the CRR was effective.

(o) Renewable Energy Credit (REC) account balances. The Protected Information status of this information shall expire three years after the REC Settlement period ends;

(p) Credit limits identifiable to a specific QSE;

(q) Any information that is designated as Protected Information in writing by Disclosing Party at the time the information is provided to Receiving Party except

for information that is expressly designated not to be Protected Information by Section 1.3.1.2 or that, pursuant to Section 1.3.1.4, is no longer confidential;

(r) Any information compiled by a Market Participant on a Customer that in the normal course of a Market Participant's business that makes possible the identification of any individual Customer by matching such information with the Customer's name, address, account number, type of classification service, historical electricity usage, expected patterns of use, types of facilities used in providing service, individual contract terms and conditions, price, current charges, billing record, or any other information that a Customer has expressly requested not be disclosed ("Proprietary Customer Information") unless the Customer has authorized the release for public disclosure of that information in a manner approved by the Public Utility Commission of Texas (PUCT). Information that is redacted or organized in such a way as to make it impossible to identify the Customer to whom the information relates does not constitute Proprietary Customer Information;

(s) Any software, products of software, or other vendor information that ERCOT is required to keep confidential under its agreements;

(t) QSE, Transmission Service Provider (TSP), and Distribution Service Provider (DSP) backup plans collected by ERCOT under the Protocols or Other Binding Documents;

[NPRR857: Replace item (t) 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:]

(t) QSE, Transmission Service Provider (TSP), Direct Current Tie Operator (DCTO), and Distribution Service Provider (DSP) backup plans collected by ERCOT under the Protocols or Other Binding Documents;

(u) Direct Current Tie (DC Tie) Schedule information. The Protected Information status of this information shall expire on the date on which ERCOT files the report with the PUCT that is required by P.U.C. SUBST. R. 25.192, Transmission Rates for Export from ERCOT, relating to energy imported and exported over DC Ties interconnected to the ERCOT System;

(v) Any Texas Standard Electronic Transaction (TX SET) transaction submitted by an LSE to ERCOT or received by an LSE from ERCOT. This paragraph does not apply to ERCOT's compliance with:

(i) PUCT Substantive Rules on performance measure reporting;

(ii) These Protocols or Other Binding Documents; or

(iii) Any Technical Advisory Committee (TAC)-approved reporting requirements;

(w) Information concerning ~~a Mothballed Generation Resource's~~the probability of return to service and expected lead time for returning to service for a Mothballed Generation Resource or Mothballed Energy Storage Resource (ESR), submitted pursuant to Section 3.14.1.9, Generation Resource-/Energy Storage Resource Status Updates;

(x) Information provided by Entities under Section 10.3.2.4, Reporting of Net Generation Capacity;

(y) Alternative fuel reserve capability and firm gas availability information submitted pursuant to Section 6.5.9.3.1, Operating Condition Notice, Section 6.5.9.3.2, Advisory, and Section 6.5.9.3.3, Watch, and as defined by the Operating Guides;

(z) Non-public financial information provided by a Counter-Party to ERCOT pursuant to meeting its credit qualification requirements as well as the QSE's form of credit support;

(aa) ESI ID, identity of Retail Electric Provider (REP), and MWh consumption associated with transmission-level Customers that submitted notice to have their Load excluded from the Solar Renewable Portfolio Standard (SRPS) calculation consistent with Section 14.5.3, End-Use Customers, and subsection (f) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program, or the Renewable Portfolio Standard (RPS) calculation consistent with subsection (j) of P.U.C. SUBST. R. 25.173 as it was effective until December 31, 2023;

(bb) Emergency operations plans submitted pursuant to P.U.C. SUBST. R. 25.53, Electric Service Emergency Operations Plans;

(cc) Information provided by a Counter-Party under Section 16.16.3, Verification of Risk Management Framework;

(dd) Any data related to Load response capabilities that are self-arranged by the LSE or pursuant to a bilateral agreement between a specific LSE and its Customers, other than data either related to any service procured by ERCOT or non-LSE-specific aggregated data. Such data includes pricing, dispatch instructions, and other proprietary information of the Load response product;

(ee) Status of Settlement Only Generators (SOGs), including Outages, limitations, or scheduled or metered output data, except that ERCOT may disclose output data from an SOG as part of an extract or forwarded TX SET transaction provided to the LSE associated with the ESI ID of the Premise where the SOG is located. The

Protected Information status of this information shall expire 60 days after the applicable Operating Day;

[NPRR829 and NPRR995: Replace applicable portions of paragraph (ee) above with the following upon system implementation:]

(ee) Status of Settlement Only Generators (SOGs) and Settlement Only Energy Storage System (SOESS), including Outages, limitations, schedules, metered output and withdrawal data, or data telemetered for use in the calculation of Real-Time Liability (RTL) as described in Section 16.11.4.3.2, Real-Time Liability Estimate, except that ERCOT may disclose metered output and withdrawal data from an SOG or SOESS as part of an extract or forwarded TX SET transaction provided to the LSE associated with the ESI ID of the Premise where the SOG is located. The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(ff) Any documents or data submitted to ERCOT in connection with an Alternative Dispute Resolution (ADR) proceeding. The Protected Information status of this information shall expire upon ERCOT's issuance of a Market Notice indicating the disposition of the ADR proceeding pursuant to paragraph (1) of Section 20.9, Resolution of Alternative Dispute Resolution Proceedings and Notification to Market Participants, except to the extent the information continues to qualify as Protected Information pursuant to another paragraph of this Section 1.3.1.1;

(gg) Reasons for and future expectations of overrides to a specific Resource's High Dispatch Limit (HDL) or Low Dispatch Limit (LDL). The Protected Information status of this information shall expire 60 days after the applicable Operating Day;

(hh) Information provided to ERCOT under Section 16.18, Cybersecurity Incident Notification, except that ERCOT may disclose general information concerning a Cybersecurity Incident in a Market Notice in accordance with paragraph (5) of Section 16.18 to assist Market Participants in mitigating risk associated with a Cybersecurity Incident;

(ii) Information disclosed in response to paragraphs (1)-(4) of the Natural Gas Pipeline Coordination section of Section 22, Attachment K, Declaration of Natural Gas Pipeline Coordination, submitted to ERCOT in accordance with Section 3.21, Submission of Declarations of Natural Gas Pipeline Coordination. The Protected Information status of Resource Outage information shall expire as provided in paragraph (1)(c) of Section 1.3.1.1;

(jj) Information concerning weatherization activities submitted to, obtained by, or generated by ERCOT in connection with P.U.C. SUBST. R. 25.55, Weather Emergency Preparedness, if such information allows the identification of any Resource or Resource Entity;

(kk) Information provided to ERCOT:

(i) By a QSE under paragraph (3) of Section 3.14.5, Firm Fuel Supply Service, as part of an offer to provide Firm Fuel Supply Service (FFSS), except that within ten Business Days of issuing FFSS awards, ERCOT may disclose the identity of all Generation Resources that were offered as primary Generation Resources or alternate Generation Resources to provide FFSS for the most recent procurement period, including prices and quantities offered;

(ii) By a Resource Entity under paragraph (2) of Section 8.1.1.2.1.6, Firm Fuel Supply Service Resource Qualification, Testing, and Decertification, as part of the voluntary process for ERCOT certification of a FFSS Qualified Contract; or

(iii) By a Resource Entity in a Force Majeure Event report required under paragraph (14) of Section 8.1.1.2.6;

(ll) Information provided to ERCOT pursuant to Section 16.2.1.1, QSE Background Check Process, or Section 16.8.1.1, CRR Account Holder Background Check Process; and

(mm) Information concerning coal or lignite inventory provided by a QSE under Section 3.24, Notification of Low Coal and Lignite Inventory Levels.

1.3.1.2 Items Not Considered Protected Information

(1) Notwithstanding the definition of "Protected Information" in Section 1.3.1.1, Items Considered Protected Information, the following items are not Protected Information even if so designated:

(a) Data comprising Load flow cases, which may include estimated peak and off-peak Demand of any Load;

(b) Existence of Power System Stabilizers (PSSs) at each interconnected Generation Resource or ESR, and PSS status (in service or out of service);

(c) Reliability Must-Run (RMR) Agreements;

(d) Studies, reports and data used in ERCOT's assessment of whether an RMR Unit satisfies ERCOT's criteria for operational necessity to support ERCOT System reliability but only if they have been redacted to exclude Protected Information under Section 1.3.1.1;

(e) Status of RMR Units;

(f) Black Start Agreements;

(g) FFSS awards;

(h) RMR Settlement charges and payments;

[NPRR885: Insert items (i) and (j) below upon system implementation and renumber accordingly:]

(i) Must-Run Alternative (MRA) Agreements;

(j) Settlement charges and payments for MRA Service;

(i) Within two Business Days of a request from a potential generating Facility for a full resource interconnection study, the county in which the Facility is located, Facility fuel type(s), Facility nameplate capacity, and anticipated Commercial Operations Date(s) and signed generation interconnection agreements; and

(j) Any other information specifically designated in these Protocols or in the PUCT Substantive Rules as information to be posted to the ERCOT website or Market Information System (MIS) Secure Area that is not specified as information that is subject to the requirements of Section 1.3, Confidentiality.

(2) Protected Information that Receiving Party is permitted or required to disclose or use under the Protocols or under an agreement between Receiving Party and a Disclosing Party does not cease to be regarded as Protected Information in all other circumstances not encompassed by these Protocols or such agreement by virtue of the permitted or required disclosure or use under these Protocols or such agreement.

1.6.5 Interconnection of New or Existing Generation ~~or Energy Storage~~

(1) Interconnection of new Generation Resources, Energy Storage Resources (ESRs), or Settlement Only Generators (SOGs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents.

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

(1) Interconnection of new Generation Resources, Energy Storage Resources (ESRs), Settlement Only Generators (SOGs), or Settlement Only Energy Storage Systems (SOESSs) to the ERCOT Transmission Grid must be in accordance with the Protocols, the Planning Guide, the Nodal Operating Guide and Other Binding Documents.

(2) For existing Generation Resources, ESRs, and SOGs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources, ESRs, and SOGs which are based upon the execution date of the Standard

Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions:

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

(2) For existing Generation Resources, ESRs, SOGs, and SOESSs which connect to a new Point of Interconnection (POI) or which utilize more than one POI to the ERCOT Transmission Grid, any Protocol or Other Binding Document requirements applicable to Generation Resources, ESRs, SOGs, and SOESSs which are based upon the execution date of the Standard Generation Interconnection Agreement (SGIA) shall be applied to the date of the first executed SGIA with the following exceptions:

(a) For a new POI, existing Generation Resources, ESRs, and Settlement Only Transmission Self-Generators (SOTSGs) shall comply with the requirements in Section 3.15, Voltage Support, and Nodal Operating Guide Section 2.9, Voltage Ride-Through Requirements for Generation Resources, based upon the execution date of the most recent SGIA.

(b) For more than one POI, existing Generation Resources, ESRs, and SOTSGs shall comply with the requirements in Section 3.15 and Nodal Operating Guide Section 2.9 based upon the execution date of the SGIA relative to the POI where the Generation Resource, ESR, or SOTSG is electrically connected.

(3) When a Municipally Owned Utility (MOU) or Electric Cooperative (EC) transferring Load into the ERCOT System owns a generation unit currently serving the transferring Load in a non-ERCOT Control Area and seeks to interconnect the generation unit to the ERCOT Transmission Grid in conjunction with the Load transfer, the interconnection will be subject to the requirements in paragraph (1) above; however, if the Protocols, Planning Guide, Nodal Operating Guide or Other Binding Documents set forth an alternate requirement for Generation Resources, ESRs, or SOGs that were installed, connected, operating, or had an SGIA executed before a specified date, then ERCOT, in its sole discretion, may apply the alternate requirement to the MOU's or EC's generation unit, subject to the following:

(a) The generation unit must have been operating in the non-ERCOT Control Area on or before the date specified in the Protocol, Planning Guide, Nodal Operating Guide or Other Binding Document provision that sets forth the alternate requirement;

(b) The generation unit has not undergone a modification pursuant to paragraph (1)(c) of Planning Guide Section 5.2.1, Applicability, subsequent to the specified date from paragraph (3) above;

(c) The MOU or EC must submit a written request to ERCOT that identifies the alternate requirement(s) it seeks to have applied and explains why compliance with

the requirement(s) applicable to new Generation Resources, ESRs or SOGs is not feasible at a reasonable cost; and

(d) The MOU or EC must demonstrate to ERCOT's satisfaction through interconnection or similar studies that allowing the generation unit to comply with the alternate requirement will not create a risk to the reliability of the ERCOT System.

2.1 DEFINITIONS

Blackout

A condition in which frequency for the entire ERCOT System has dropped to zero and Generation Resources and Energy Storage Resources (ESRs) are no longer serving Load.

Partial Blackout

A condition in which an uncontrolled separation of a portion of the ERCOT System occurs and frequency for that portion has dropped to zero and Generation Resources and ESRs within that portion are no longer serving Load and restoration is dependent on either internal Black Start Plans or assistance for restoration is needed from neighboring Transmission Operator(s) (TO(s)) within the ERCOT System which requires ERCOT coordination.

Credible Single Contingency

(1) The Forced Outage of any single Transmission Facility or, during a single fault, the Forced Outage of multiple Transmission Facilities (single fault multiple element);

(2) The Forced Outage of a double-circuit transmission line in excess of 0.5 miles in length;

(3) The Forced Outage of any single Generation Resource or Energy Storage Resource (ESR), and in the case of a Combined Cycle Train, the Forced Outage of the combustion turbine and the steam turbine if they cannot operate separately as provided in the Resource registration process; or

(4) For transmission planning purposes, contingencies are defined in the Planning Guide.

Emergency Response Service (ERS) Generator

Either (1) an individual generator contracted to provide ERS which is ~~not~~neither a Generation Resource, nor a source of intermittent renewable generation, nor an Energy Storage Resource (ESR) and which provides ERS by injecting energy to the ERCOT System, or (2) an aggregation of such generators.

ERCOT System Demand

The sum of all power flows, in MW, on the DC Ties and from Generation Resources and Energy Storage Resources (ESRs) in discharge mode, metered at the points of their interconnections with the ERCOT System at any given time.

[NPRR1013: Insert the following definition "Frequency Responsive Capacity (FRC)" upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Frequency Responsive Capacity (FRC)

The telemetered portion of ~~a Generation Resource's~~the total MW output of a Generation Resource or Energy Storage Resource (ESR) that represents the fraction of the ~~output provided from~~ capacity that is capable of providing Primary Frequency Response. Capacity not capable of providing Primary Frequency Response includes, but may not be limited to, capacity from duct firing, auxiliary boilers, and other methods that do not immediately respond, arrest, or stabilize frequency excursions following a disturbance without secondary frequency response or instructions from ERCOT.

Generation Entity

The owner of a Generation Resource, Energy Storage Resources (ESR), or Settlement Only Generator (SOG) and, unless otherwise specified in these Protocols, is registered as a Resource Entity.

[NPRR995: Replace the above definition "Generation Entity" with the following upon system implementation:]

Generation Entity

The owner of a Generation Resource, Energy Storage Resource (ESR), Settlement Only Energy Storage System (SOESS), or Settlement Only Generator (SOG) and, unless otherwise specified in these Protocols, is registered as a Resource Entity.

Initial Energization

The first time a Generation Resource, Energy Storage Resources (ESR), or Settlement Only Generator (SOG) 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.

Initial Synchronization

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

[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.

Load Frequency Control (LFC)

The deployment of those Controllable Load Resources, ~~and~~ Generation Resources, and Energy Storage Resources (ESRs) that are providing Regulation Service to ensure that system frequency is maintained within predetermined limits and the deployment of those ~~Controllable Load Resources and Generation~~ Resources that are providing ERCOT Contingency Reserve Service (ECRS) when necessary as backup regulation. LFC does include the deployment of Responsive Reserve (RRS) (manual) and ECRS from Generation Resources, ~~and~~ Controllable Load Resources, and ESRs. LFC does not include the deployment of ECRS or RRS by Load Resources when deployed as a block under Energy Emergency Alert (EEA) procedures.

Meter Reading Entity (MRE)

A TSP or DSP that is responsible for providing ERCOT with ESI ID level consumption data as defined in Section 19, Texas Standard Electronic Transaction. In the case of an EPS Meter or ERCOT-populated ESI ID data ~~(such as Generation Resource site Load)~~, ERCOT will be identified as the MRE in ERCOT systems.

Must-Run Alternative (MRA)

A resource operated under the terms of an Agreement with ERCOT as an alternative to a Reliability Must-Run (RMR) Unit.

[NPRR885 and NPRR995: Replace applicable portions of the above definition "Must-Run Alternative (MRA)" with the following upon system implementation:]

Must-Run Alternative (MRA)

A resource operated under the terms of an Agreement with ERCOT as an alternative to a Reliability Must-Run (RMR) Unit. An MRA may be one of the following:

Generation Resource MRA

A generator that is registered with ERCOT as a Generation Resource that is dispatchable in Security-Constrained Economic Dispatch (SCED) and is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT.

Energy Storage Resource MRA

An Energy Storage Resource that is registered with ERCOT as an Energy Storage Resource that is dispatchable in Security-Constrained Economic Dispatch (SCED) and is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT.

Other Generation MRA

Unregistered generation, or generation registered with ERCOT that is not dispatchable in Security-Constrained Economic Dispatch (SCED), that is providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT. An Other Generation MRA may include, but is not limited to, Settlement Only Generators (SOGs), Settlement Only Energy Storage Systems (SOESSs), and Distributed Generation (DG).

Demand Response MRA

A Load providing Must-Run Alternative (MRA) Service under an Agreement with ERCOT by reducing energy consumption in response to an ERCOT instruction. A Demand Response MRA may be an unregistered Load or a registered Load Resource other than a Controllable Load Resource.

Weather-Sensitive MRA

A type of Must-Run Alternative (MRA) Service in which a Demand Response MRA provides MRA Service only after meeting the qualification requirements for weather sensitivity set forth in paragraph (5) of Section 3.14.3.1, Emergency Response Service Procurement.

[NPRR885: Insert the following definition "Must-Run Alternative (MRA) Contracted Hour(s)" upon system implementation:]

Must-Run Alternative (MRA) Contracted Hour(s)

The hour(s) during which an MRA is contracted under an MRA Agreement to provide MRA Service.

Outage

The condition of a Transmission Facility or a portion of a Facility, or Generation Resource or Energy Storage Resources (ESR) that is part of the ERCOT System and defined in the Network Operations Model that has been removed from its normal service, excluding the operations of Transmission Facilities associated with the start-up and shutdown of ~~Generation~~ Resources.

Forced Outage

An Outage initiated by protective relay, or manually in response to an observation by personnel that the condition of equipment could lead to an event, or potential event, that poses a threat to people, equipment, or public safety.

For a Generation Resource or ESR, an Outage that requires immediate removal, either through controlled or uncontrolled actions, of all or a portion of the capacity of the Resource from service through automated or manual means. This type of Outage usually results from immediate mechanical/electrical/hydraulic control system trips and operator-initiated actions in response to a Resource's condition.

High Impact Outage (HIO)

A Planned Outage or Rescheduled Outage that interrupts flow on a High Impact Transmission Element (HITE).

Maintenance Outage

An Outage initiated manually to remove equipment from service to perform work on components that could be postponed briefly but that is required to prevent a potential Forced Outage and that cannot be postponed until the next Planned Outage. Maintenance Outages are classified as follows:

(1) **Level I Maintenance Outage** – Equipment that must be removed from service within 24 hours to prevent a potential Forced Outage;

(2) **Level II Maintenance Outage** – Equipment that must be removed from service within seven days to prevent a potential Forced Outage; and

(3) **Level III Maintenance Outage** – Equipment that must be removed from service within 30 days to prevent a potential Forced Outage.

Opportunity Outage

An Outage that may be accepted by ERCOT when a specific Resource is Off-Line due to an Outage.

Planned Outage

An Outage that is planned and scheduled in advance with ERCOT, other than a Maintenance Outage or Opportunity Outage.

Rescheduled Outage

An Outage on a High Impact Transmission Element (HITE) that was originally submitted as a Planned Outage with more than 90-days' notice and approved, but is then rescheduled due to withdrawal of approval by ERCOT of the original Planned Outage or subsequent Rescheduled Outage(s).

Simple Transmission Outage

A Planned Outage or Maintenance Outage of any Transmission Element in the Network Operations Model such that when the Transmission Element is removed from its normal service, absent a Forced Outage of other Transmission Elements, the Outage does not cause a topology change in the LMP calculation and thus cannot cause any LMPs to change with or without the Transmission Element that is suffering the Outage.

Power System Stabilizer (PSS)

A device or control that is installed on a synchronous machine to provide oscillation dampening support to ~~that is installed on Generation Resources to maintain synchronous operation of~~ the ERCOT System under transient conditions.

Resource

The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term "Resource" used by itself in these Protocols does not include a Settlement Only Generator (SOG) or an Emergency Response Service (ERS) Resource.

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

Resource

The term is used to refer to an Energy Storage Resource (ESR), a Generation Resource, or a Load Resource. The term "Resource" used by itself in these Protocols does not include a Settlement Only Generator (SOG), Settlement Only Energy Storage System (SOESS), or an Emergency Response Service (ERS) Resource.

Energy Storage Resource (ESR)

An Energy Storage System (ESS) registered with ERCOT for the purpose of providing energy and/or Ancillary Service to the ERCOT System.

[NPRR1029: Insert the following definition "DC-Coupled Resource upon system implementation:]

DC-Coupled Resource

A type of Energy Storage Resource (ESR) in which an Energy Storage System (ESS) is combined with wind and/or solar generation in the same modeled generation station and interconnected at the same Point of Interconnection (POI), and where these technologies are interconnected within the site using direct current (DC) equipment. The combined technologies are then connected to the ERCOT System using the same direct current-to-alternating current (DC-to-AC) inverter(s). To be classified as a DC-Coupled Resource, the generator(s) and ESS(s) at a site must meet the following conditions:

(1) The ESS component of the Resource must have a nameplate rating of at least ten MW and ten MWh, or the MW rating must equal or exceed 50% of the nameplate MW rating of the inverter; and

(2) All intermittent renewable generators must meet the conditions for aggregation stated in paragraph (13) of Section 3.10.7.2, Modeling of Resources and Transmission Loads, except to the extent any such condition requires the generator to be a Resource.

Distribution Energy Storage Resource (DESR)

An Energy Storage Resource (ESR) connected to the Distribution System that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator, or

(2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets.

Transmission Energy Storage Resource (TESR)

An Energy Storage Resource (ESR) connected to the ERCOT transmission system that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator, or

(2) Greater than one MW that chooses to register as a Resource with ERCOT to participate in the ERCOT markets.

Generation Resource

A generator capable of providing energy or Ancillary Service to the ERCOT System and is registered with ERCOT as a Generation Resource.

Distribution Generation Resource (DGR)

A Generation Resource connected to the Distribution System that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets.

Transmission Generation Resource (TGR)

A Generation Resource connected to the ERCOT transmission system that is either:

(1) Greater than ten MW and not registered with the Public Utility Commission of Texas (PUCT) as a self-generator; or

(2) Greater than one MW that chooses to register as a Generation Resource to participate in the ERCOT markets.

Load Resource

A Load capable of providing Ancillary Service to the ERCOT System and/or energy in the form of Demand response and registered with ERCOT as a Load Resource.

Aggregate Load Resource (ALR)

A Controllable Load Resource that is an aggregation of individual metered sites, each of which has less than ten MW of Demand response capability and all of which are located within a single Load Zone.

Controllable Load Resource

A Load Resource capable of controllably reducing or increasing consumption under Dispatch control by ERCOT.

Settlement Only Generator (SOG)

A generator that is settled for exported energy only, but may not participate in the Ancillary Services market, Reliability Unit Commitment (RUC), Security-Constrained Economic Dispatch (SCED), or make energy offers. These units are comprised of:

[NPRR995: Delete the above definition "Settlement Only Generator (SOG)" upon system implementation.]

Settlement Only Distribution Generator (SODG)

A generator that is connected to the Distribution System with a rating of:

(1) One MW or less that chooses to register as an SODG; or

(2) Greater than one and up to ten MW that is capable of providing a net export to the ERCOT System and does not register as a Distribution Generation Resource (DGR).

SODGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

[NPRR995: Delete the above definition "Settlement Only Distribution Generator (SODG)" upon system implementation.]

Settlement Only Transmission Generator (SOTG)

A generator that is connected to the ERCOT transmission system with a rating of ten MW or less and is registered with the Public Utility Commission of Texas (PUCT) as a power generation company. SOTGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and may be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.2, Modeling of Resources and Transmission Loads.

[NPRR995: Delete the above definition "Settlement Only Transmission Generator (SOTG)" upon system implementation.]

Settlement Only Transmission Self-Generator (SOTSG)

A generator that is connected to the ERCOT transmission system with a rating of one MW or more and is registered with the Public Utility Commission of Texas (PUCT) as a self-generator. SOTSGs must be registered with ERCOT in accordance with Planning Guide Section 6.8.2, Resource Registration Process, and will be modeled in ERCOT systems for reliability in accordance with Section 3.10.7.3, Modeling of Private Use Networks.

[NPRR995: Delete the above definition "Settlement Only Transmission Self-Generator (SOTSG)" upon system implementation.]

Resource Attribute

Specific qualities associated with various Resources (i.e., specific aspects of a Resource or the services the Resource is qualified to provide).

Aggregate Generation Resource (AGR)

A Generation Resource that is an 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, each of which is less than 20 MW in output, which share identical operational characteristics and are located behind the same Main Power Transformer (MPT).

Black Start Resource

A Generation Resource under contract with ERCOT to provide Black Start Service (BSS).

Combined Cycle Train

The combinations of gas turbines and steam turbines in an electric generation plant that employs more than one thermodynamic cycle. For example, a Combined Cycle Train refers to the combination of gas turbine generators (operating on the Brayton Cycle) with turbine exhaust waste heat boilers and steam turbine generators (operating on the Rankine Cycle) for the production of electric power. In the ERCOT market, Combined Cycle Trains are each registered as a plant that can operate as a Generation Resource in one or more Combined Cycle Generation Resource configurations.

Decommissioned Generation Resource

A Generation Resource for which a Resource Entity has submitted a Notification of Suspension of Operations or a Notification of Change of Generation Resource Designation, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has been decommissioned and permanently retired.

Dynamically Scheduled Resource (DSR)

A Resource that has been designated by the Qualified Scheduling Entity (QSE), and approved by ERCOT, as a DSR status-type and that follows a DSR Load.

[NPRR1000: Delete the definition "Dynamically Scheduled Resource (DSR)" above upon system implementation.]

Intermittent Renewable Resource (IRR)

A Generation Resource that can only produce energy from variable, uncontrollable Resources, such as wind, solar, or run-of-the-river hydroelectricity.

Intermittent Renewable Resource (IRR) Group

A group of two or more IRRs whose performance in responding to Security-Constrained Economic Dispatch (SCED) Dispatch Instructions will be assessed as an aggregate for Generation Resource Energy Deployment Performance (GREDP) and Base Point Deviation. An IRR Group cannot contain any IRRs that are Split Generation Resources. Additionally, only IRRs that have the same Resource Node can be mapped to an IRR Group. Resource Entities can choose to group IRRs and shall provide the grouping information in a timely manner for ERCOT review prior to the scheduled database loads.

[NPRR1013: Replace the definition "Intermittent Renewable Resource (IRR) Group" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

Intermittent Renewable Resource (IRR) Group

A group of two or more IRRs whose performance in responding to Security-Constrained Economic Dispatch (SCED) Dispatch Instructions will be assessed as an aggregate for Generation Resource Energy Deployment Performance (GREDP) and Set Point Deviation. An IRR Group cannot contain any IRRs that are Split Generation Resources. Additionally, only IRRs that have the same Resource Node can be mapped to an IRR Group. Resource Entities can choose to group IRRs and shall provide the grouping information in a timely manner for ERCOT review prior to the scheduled database loads.

Inverter-Based Resource (IBR)

A Resource that is connected to the ERCOT System either completely or partially through a power electronic converter interface.

Mothballed Generation Resource

A Generation Resource for which a Resource Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has not been decommissioned and retired.

Mothballed Energy Storage Resource

An Energy Storage Resource (ESR) for which a Resource Entity has submitted a Notification of Suspension of Operations, for which ERCOT has declined to execute a Reliability Must-Run (RMR) Agreement, and which has not been decommissioned and retired.

Quick Start Generation Resource (QSGR)

A Generation Resource that in its cold-temperature state can come On-Line within ten minutes of receiving ERCOT notice and has passed an ERCOT QSGR test that establishes an amount of capacity that can be deployed within a ten-minute period.

Split Generation Resource

Where a Generation Resource has been split to function as two or more independent Generation Resources in accordance with Section 10.3.2.1, Generation Resource Meter Splitting, and Section 3.10.7.2, Modeling of Resources and Transmission Loads, each such functionality independent Generation Resource is a Split Generation Resource.

Switchable Generation Resource (SWGR)

A Generation Resource that can be connected to either the ERCOT Transmission Grid or a non-ERCOT Control Area.

Seasonal Operation Period

The period in which a Generation Resource or Energy Storage Resource (ESR) has identified it is available for operation.

Subsynchronous Oscillation (SSO)

Coincident oscillation occurring between two or more Transmission Elements, ~~or~~ Generation Resources, or Energy Storage Resources (ESRs) 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:

Torsional Interaction

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

Induction Generator Effect (IGE)

An electrical phenomena in which a resonance involving a Generation Resource or ESR 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 or ESRs 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 or ESRs.

Subsynchronous Resonance (SSR) Countermeasures

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

Subsynchronous Resonance (SSR) Protection

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

Subsynchronous Resonance (SSR) Mitigation

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

Unit Reactive Limit (URL)

The maximum quantity of Reactive Power that a Generation Resource or Energy Storage Resource (ESR) is capable of providing at a 0.95 power factor at its maximum real power capability.

2.2 ACRONYMS AND ABBREVIATIONS

TESR Transmission Energy Storage Resource

3.1.1 Role of ERCOT

Commented [CP1]: Please note NPRR1234 also proposes revisions to this section.

(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 and Energy Storage Resources (ESRs) that do not have SSR 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.

3.1.3.2 Resources

(1) Each Resource Entity shall provide to ERCOT a Planned Outage and Maintenance Outage plan for Generation Resources and ESRs in an ERCOT-provided format for at least the next 12 months updated monthly. Planned Outage and Maintenance Outage plans must be updated as soon as practicable following any change. Updates, through an electronic interface as specified by ERCOT, must identify any changes to previously proposed Planned Outages or Maintenance Outages and any additional Planned Outages or Maintenance Outages.

(2) ERCOT shall report statistics monthly on how Resource Planned Outages compare with actual Resource Outages, and post those statistics to the MIS Secure Area.

[NPRR1240: Replace paragraph (2) above with the following upon system implementation:]

(2) ERCOT shall report statistics monthly on how Resource Planned Outages compare with actual Resource Outages, and post those statistics to the ERCOT website.

3.1.4.5 Notice of Forced Outage or Unavoidable Extension of Planned, Maintenance,

or Rescheduled Outage Due to Unforeseen Events

(1) If a Planned, Maintenance, or Rescheduled Outage is not completed within the ERCOT-approved timeframe and the Transmission Facilities or Resources are in such a condition that they cannot be restored at the Outage schedule completion date, the requesting party shall submit to ERCOT a Forced Outage (unavoidable extension) form describing the extension of the Outage and providing a revised return date.

(2) Any transmission Forced Outage that occurs in Real-Time and that is expected to continue for longer than two hours must be entered into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Outage. Any transmission Forced Outage with a duration exceeding two hours must be entered into the Outage Scheduler as soon as practicable but no longer than 150 minutes after the beginning of the transmission Forced Outage, if not already reported in the Outage Scheduler.

(3) Any Resource Forced Outage that occurs in Real-Time must be entered into the Outage Scheduler as soon as practicable but no longer than 60 minutes after the beginning of the Forced Outage.

(4) If the QSE is to receive the exemption described in paragraph (6)(d) of Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, the QSE will notify ERCOT Operators by voice communication of every Forced Outage, Forced Derate, or Startup Loading Failure within 15 minutes.

(5) For a Startup Loading Failure, the Resource Entity or its designee must enter a Forced Outage in the Outage Scheduler if the Resource was in an Off-Line status prior to the Startup Loading Failure or update the existing Outage for the Resource if the Resource was on Outage prior to the Startup Loading Failure. The Resource Entity or its designee must also provide a text entry in the supporting information field of the Outage Scheduler that includes the following:

(a) A statement that a Startup Loading Failure occurred;

(b) An explanation of the cause of the Startup Loading Failure using the best available information at the time the Outage or update to the existing Outage is entered, which must be updated if more accurate information becomes available; and

(c) The start time and end time of the Startup Loading Failure portion of the Outage. Multiple consecutive startup attempts may be aggregated into a single Startup Loading Failure event with a single start and end time.

3.1.5.1 ERCOT Evaluation of Planned Outage and Maintenance Outage of

Transmission Facilities

(1) A TSP or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP requests, the TSPs shall enter such requests in the Outage Scheduler. For Resource Entity requests, the Resource Entity shall enter such requests in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP enters the breaker and switch statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP or Resource Entity in accordance with this Section constitutes a request for ERCOT's approval of the Outage Schedule associated with the Planned Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

[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) A TSP, DCTO, or Resource Entity shall request a Planned Outage or Maintenance Outage when any Transmission Facility that is part of the ERCOT Transmission Grid and defined in the Network Operations Model will be removed from its normal service. For Resource Entities within a Private Use Network, this only includes Transmission Facilities at the Point of Interconnection (POI). For TSP, DCTO, and Resource Entity requests, the requesting Entity shall enter such a request in the Outage Scheduler. Planned Outages, Maintenance Outages, or Rescheduled Outages for Electrical Buses will be treated as consequentially outaged Transmission Elements. In those cases where a TSP or DCTO enters the breaker and switch statuses associated with an Electrical Bus, a downstream topology processor will evaluate the breakers and switches associated with the applicable Electrical Bus to determine if the Electrical Bus is consequentially outaged, and to thereby designate the status of the Electrical Bus. Proposed Transmission Planned Outage or Maintenance Outage information submitted by a TSP, DCTO, or Resource Entity in accordance with this Section constitutes a request for ERCOT's approval of the Outage Schedule associated with the Planned

Outage or Maintenance Outage. ERCOT is not deemed to have approved the Outage Schedule associated with the Planned Outage or Maintenance Outage until ERCOT notifies the TSP, DCTO, or Resource Entity of its approval under procedures adopted by ERCOT. ERCOT shall evaluate requests under Section 3.1.5.11, Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests.

(2) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities.

[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) ERCOT shall review and approve Planned Outages and Maintenance Outages of Transmission Facilities schedules. ERCOT shall transmit its approvals and rejections to TSPs and DCTOs via the ERCOT Outage Scheduler. Once approved, ERCOT may not withdraw its approval except under the conditions described in Section 3.1.5.7, Withdrawal of Approval of Approved Planned Outages, Maintenance Outages, and Rescheduled Outages of Transmission Facilities.

(3) Private Use Network Outage requests submitted pursuant to this Section shall not be publicly posted.

(4) To the extent authorized by its tariff, an External Load Serving Entity (ELSE) or Non-Opt-In Entity (NOIE) that provides retail service to a Resource Entity that owns or operates a Generation Resource or ESR may request that the TSP to which the ~~Generation~~ Resource is interconnected disconnect the ~~Generation~~ Resource due to the Resource Entity's failure to comply with the payment requirements in the ELSE's or NOIE's retail tariff.

(5) Within five Business Days after receiving a request from a Load Serving Entity (LSE) to disconnect a Generation Resource or ESR due to the Resource Entity's failure to comply with LSE's payment requirements, including a request received pursuant to paragraph (4) above, the interconnecting TSP shall enter a request in the Outage Scheduler for an Outage of any Transmission Facilities interconnecting the ~~Generation~~ Resource to the ERCOT System. Any Outage requested or taken pursuant to this Section shall be treated as a Planned Outage for all purposes under the Protocols. For any such Outage request,

the requesting TSP shall enter a start date that it is at least four days after the date the request is submitted in the Outage Scheduler and shall enter an Outage end date that is 14 days from the date of the requested start date. Unless storm or system reliability issues prevent immediate dispatch of personnel, for any LSE request to reconnect a Customer that was disconnected pursuant to this section, the interconnecting TSP shall end the Outage and reconnect the ~~Generation~~ Resource the same Business Day if the request is received by 1200, or the next Business Day if the request is received after 1200. If a reconnect request is not received within four days of the Outage end date, the interconnecting TSP shall enter another request in the Outage Scheduler for an Outage of any Transmission Facilities interconnecting the ~~Generation~~ Resource to the ERCOT System with an Outage end date 14 days beyond the prior Outage end date. At any time, ERCOT may withdraw approval of the Outage and instruct the TSP to reconnect the ~~Generation~~ Resource if it deems cancellation necessary to address reliability concerns.

3.1.5.11 Evaluation of Transmission Facilities Planned Outage or Maintenance Outage Requests

Commented [CP2]: Please note NPRR1234 also proposes revisions to this section.

(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 or ESRs that do not have SSR 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.

3.6.1 Load Resource Participation

Commented [CP3]: Please note NPRR1241 also proposes revisions to this section.

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

(i) Regulation Up (Reg-Up) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(ii) Regulation Down (Reg-Down) Service as a Controllable Load Resource capable of providing Primary Frequency Response;

(iii) Responsive Reserve (RRS) as a Controllable Load Resource qualified for Security-Constrained Economic Dispatch (SCED) Dispatch and capable of providing Primary Frequency Response, or as a Load Resource controlled by high-set under-frequency relay;

(iv) ERCOT Contingency Reserve Service (ECRS) as a Controllable Load Resource qualified for SCED Dispatch and capable of providing Primary Frequency Response, or as a Load Resource that may or may not be controlled by high-set under-frequency relay;

[NPRR1244: Replace paragraph (iv) above with the following upon system implementation:]

(iv) ERCOT Contingency Reserve Service (ECRS) as a CLR qualified for SCED Dispatch, or as a Load Resource that may or may not be controlled by high-set under-frequency relay;

(v) Non-Spinning Reserve (Non-Spin) as a Controllable Load Resource qualified for SCED Dispatch or as a Load Resource that is not a Controllable Load Resource and that is not controlled by under-frequency relay; and

(vi) A Load Resource that is not a Controllable Load Resource cannot simultaneously provide Non-Spin and RRS in Real-Time;

(b) Energy in the form of Demand response from a Controllable Load Resource in Real-Time via SCED;

(c) Emergency Response Service (ERS) for hours in which the Load Resource does not have an Ancillary Service Resource Responsibility; and

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

(c) Emergency Response Service (ERS) for hours in which the Load Resource has a Resource Status of OUTL; and

(d) Voluntary Load response in Real-Time.

(2) Except for voluntary Load response and ERS, loads participating in any ERCOT market must be registered as a Load Resource and are subject to qualification testing administered by ERCOT.

(3) All ERCOT Settlements resulting from Load Resource participation are made only with the Qualified Scheduling Entity (QSE) representing the Load Resource.

(4) A QSE representing a Load Resource and submitting a bid to buy for participation in SCED, as described in Section 6.4.3.1, RTM Energy Bids, must represent the Load Serving Entity (LSE) serving the Load of the Load Resource. If the Load Resource is an Aggregate Load Resource (ALR), the QSE must represent the LSE serving the Load of all sites within the ALR.

(5) The Settlement Point for a Controllable Load Resource is its Load Zone Settlement Point. ~~For an Energy Storage Resource (ESR), the Settlement Point for the charging Load withdrawn by the modeled Controllable Load Resource associated with the ESR is the Resource Node of the modeled Generation Resource associated with the ESR.~~

[NPRR1188: Replace paragraph (5) above with the following upon system implementation:]

(5) The Settlement Point for a CLR that is not an ALR is its Resource Node Settlement Point. The Settlement Point for an ALR is its Load Zone Settlement Point. ~~For an Energy Storage Resource (ESR), the Settlement Point for the charging Load withdrawn by the modeled CLR associated with the ESR is the Resource Node of the modeled Generation Resource associated with the ESR.~~

(6) QSEs shall not submit offers for Load Resources containing sites associated with a Dynamically Scheduled Resource (DSR).

[NPRR1000: Delete paragraph (6) above upon system implementation and renumber accordingly.]

(7) Each Resource Entity that represents one or more Load Resources shall ensure that each Load Resource it represents meets at least one of the following conditions:

(a) The Load Resource is not located behind an Electric Service Identifier (ESI ID) that corresponds to a Critical Load;

(b) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but the Load Resource is not a Critical Load and does not include a Critical Load; or

(c) The Load Resource is located behind an ESI ID that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site.

(8) As a condition of obtaining and maintaining registration as a Load Resource, the Resource Entity for the Load Resource must have submitted an attestation, in a form deemed acceptable by ERCOT, stating that one of the conditions set forth in paragraph (7) above is true, and that if either of the conditions in paragraph (7)(b) or (7)(c) is true, then all of the Load Resource's offered Demand response capacity will be available if deployed by ERCOT during an emergency.

(9) Each QSE that represents one or more ERS Resources shall ensure that each ERS Resource identified in any ERS Submission Form submitted by the QSE meets at least one of the following conditions:

(a) The ERS Resource and each site within the ERS Resource are not located behind an ESI ID or unique meter identifier that corresponds to a Critical Load and are not used to support a Critical Load; or

(b) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but the ERS Resource and each site within the ERS Resource are not a Critical Load, do not include a Critical Load, and are not used to support a Critical Load; or

(c) The ERS Resource or one or more sites within the ERS Resource are behind an ESI ID or unique meter identifier that corresponds to a Critical Load, but electric service from the ERCOT System is not required for the provision of the critical service due to the availability of back-up generation or other technologies at the site, and neither the ERS Resource nor any site within the ERS Resource is used to support a Critical Load.

3.8.5 Energy Storage Resources

~~(1) For the purposes of all ERCOT Protocols and Other Binding Documents, all requirements that apply to Generation Resources and Controllable Load Resources shall be understood to apply to Energy Storage Resources (ESRs) to the same extent, except where the Protocols explicitly provide otherwise.~~

(1~~2~~) A QSE representing an ESR may update the telemetered HSL and/or Maximum Power Consumption (MPC) for the ESR in Real-Time to ensure the ability to meet the ESR's full Ancillary Service Resource Responsibility for the current Operating Hour. This provision only applies when the MOC for an ESR is set at the System-Wide Offer Cap (SWCAP) pursuant to paragraph (1)(b) of Section 4.4.9.4.1, Mitigated Offer Cap.

[NPRR1075: Delete paragraph (12) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

(23) A QSE representing an ESR may update the telemetered HSL and/or MPC for the ESR in Real-Time to reflect state of charge limitations.

[NPRR1075: Replace paragraph (23) above with the following upon system implementation of NPRR1014:]

(23) A QSE representing an ESR may update the telemetered HSL and/or LSL for the ESR in Real-Time to reflect state of charge limitations.

(34) A QSE representing an ESR co-located with a Generation Resource may reduce the telemetered MPC of the Controllable Load Resource modeled to represent the charging side of the ESR when self-charging using output from the Generation Resource. Such reduction in MPC shall be equal to the MW level of self-charge.

[NPRR1075: Replace paragraph (34) above with the following upon system implementation of NPRR1014:]

(34) A QSE representing an ESR co-located with a Generation Resource may update the telemetered LSL of the ESR when self-charging (using output from the Generation Resource). The updated LSL shall be equal to the MW level of self-charge.

3.10.1 Time Line for Network Operations Model Changes

(1) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement planned transmission and Resource construction one year before the required submittal date below. TSPs and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

[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) ERCOT shall perform periodic updates to the Network Operations Model. Market Participants may provide Network Operations Model updates to ERCOT to implement

planned transmission and Resource construction one year before the required submittal date below. TSPs, DCTOs, and Resource Entities must timely submit Network Operations Model changes pursuant to the schedule in this Section to be included in the updates.

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) as described in Planning Guide Section 5, Generator ~~Energy Storage System~~ Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation ~~or Energy Storage~~ to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, ESR, or SOG.

[NPRR995: Replace paragraph (2) above with the following upon system implementation:]

(2) For a facility addition, revision, or deletion to be included in any Network Operations Model update, all technical modeling information must be submitted to ERCOT pursuant to the ERCOT NOMCR process or the applicable Resource Registration process for Resource Entities. If a Resource Entity is required to follow the generation interconnection process for a new Generation Resource, Settlement Only Generator (SOG), or Settlement Only Energy Storage System (SOESS) as described in Planning Guide Section 5, Generator Interconnection or Modification, it must meet the conditions of Planning Guide Section 6.9, Addition of Proposed Generation to the Planning Models, before submitting a change to the Network Operations Model to reflect the new Generation Resource, SOG, or SOESS.

(3) TSPs and Resource Entities shall submit Network Operations Model updates at least three months prior to the physical equipment change. ERCOT shall update the Network Operations Model according to the following table:

Deadline to Submit Information to ERCOT Note 1	Model Complete and Available for Test Note 2	Updated Network Operations Model Testing Complete Note 3 Paragraph (5)	Update Network Operations Model Production Environment	Target Physical Equipment included in Production Model Note 4
Jan 1	Feb 15	March 15	April 1	Month of April
Feb 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Month of June
April 1	May 15	June 15	July 1	Month of July
May 1	June 15	July 15	August 1	Month of August

Deadline to Submit Information to ERCOT Note 1	Model Complete and Available for Test Note 2	Updated Network Operations Model Testing Complete Note 3 Paragraph (5)	Update Network Operations Model Production Environment	Target Physical Equipment included in Production Model Note 4
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. TSP and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.
4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

[NPRR857 and NPRR1254: Replace applicable portions of 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 for NPRR857; or on March 1, 2025 for NPRR1254:]

(3) TSPs, DCTOs, and Resource Entities shall submit all Network Operations Model updates that are not subject to the requirements of paragraph (4) below by the applicable deadline to submit information to ERCOT for the target date of inclusion in the

production model detailed in the table below. ERCOT shall update the Network Operations Model according to the following table:

Deadline to Submit Information to ERCOT Note 1	Model Complete and Available for Test Note 2	Updated Network Operations Model Testing Complete Note 3 Paragraph (6)	Update Network Operations Model Production Environment	Target Physical Equipment included in Production Model Note 4
January 1	February 15	March 15	April 1	Month of April
February 1	March 15	April 15	May 1	Month of May
March 1	April 15	May 15	June 1	Month of June
April 1	May 15	June 15	July 1	Month of July
May 1	June 15	July 15	August 1	Month of August
June 1	July 15	August 15	September 1	Month of September
July 1	August 15	September 15	October 1	Month of October
August 1	September 15	October 15	November 1	Month of November
September 1	October 15	November 15	December 1	Month of December
October 1	November 15	December 15	January 1	Month of January (the next year)
November 1	December 15	January 15	February 1	Month of February (the next year)
December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. TSP, DCTO, and Resource Entity data submissions complete per the NOMCR process or other ERCOT-prescribed process applicable to Resource Entities for inclusion in next update period.
2. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4, ERCOT Responsibilities. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
3. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the Energy Management System (EMS) testing prior to placing the new model into the production environment.
4. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

[NPRR1254: Insert paragraph (4) below on March 1, 2025 and renumber accordingly:]

(4) Resource Entities shall submit complete initial Resource Registration data for inclusion in the ERCOT Network Operations Model as described in paragraph (6) of Planning Guide Section 6.8.1, Resource Registration, by the applicable deadline for the Resource Entity to submit complete information to ERCOT for the target date of inclusion in the production model detailed in the table below. ERCOT shall update the Network Operations Model according to the following table:

Deadline for Resource Entity to Submit Complete Information to ERCOT **Note 1**	**Deadline for Resource Registration Data to Meet Criteria for ERCOT Acceptance** **Note 2**	**Model Complete and Available for Test** **Note 3**	**Updated Network Operations Model Testing Complete** **Note 4** **Paragraph (6)**	**Update Network Operations Model Production Environment**	**Target Physical Equipment included in Production Model** **Note 5**
December 1	January 1	February 15	March 15	April 1	Month of April
January 1	February 1	March 15	April 15	May 1	Month of May
February 1	March 1	April 15	May 15	June 1	Month of June
March 1	April 1	May 15	June 15	July 1	Month of July
April 1	May 1	June 15	July 15	August 1	Month of August
May 1	June 1	July 15	August 15	September 1	Month of September
June 1	July 1	August 15	September 15	October 1	Month of October
July 1	August 1	September 15	October 15	November 1	Month of November
August 1	September 1	October 15	November 15	December 1	Month of December
September 1	October 1	November 15	December 15	January 1	Month of January (the next year)
October 1	November 1	December 15	January 15	February 1	Month of February (the next year)
November 1	December 1	January 15	February 15	March 1	Month of March (the next year)

Notes:

1. The date listed in this column shall serve as the deadline for initial submission of complete Resource Registration data to ERCOT, as described in paragraph (2) of Planning Guide Section 6.8.2, Resource Registration Process. ERCOT may work with the Resource Entity to resolve any data quality issues found in the Resource Registration data for up to one month after the submission date that corresponds to the date listed in this column. If ERCOT determines any Resource Registration data

deficiencies are not sufficiently resolved by the end of the one-month period, then that submission shall be treated as a new initial submission for the following month.

2. Resource Entity data submission must be deemed complete by ERCOT with all data deficiencies resolved per the process described in Planning Guide Section 6.8.2 by this date.
3. Network Operations Model data changes and preliminary fidelity test complete by using the Network Operations Model test facility described in paragraph (3) of Section 3.10.4. A test version of the Redacted Network Operations Model will be posted to the MIS Secure Area for Market Participants and Network Operations Model to the MIS Certified Area for TSPs as described in paragraph (9) of Section 3.10.4, for market review and further testing by Market Participants.
4. Testing of the Redacted Network Operations Model by Market Participants and Network Operations Model by TSPs is complete and ERCOT begins the EMS testing prior to placing the new model into the production environment.
5. Updates include changes starting at this date and ending within the same month. The schedule for Operations Model load dates will be published by ERCOT on the ERCOT website.

(4) ERCOT shall only approve energization requests when the Transmission Element is satisfactorily modeled in the Network Operations Model.

(5) Changes to an existing NOMCR that modify only Inter-Control Center Communications Protocol (ICCP) data object names shall be provided 15 days prior to the Network Operations Model load date. NOMCR modifications containing only ICCP data object names shall not be subject to interim update reporting to the Independent Market Monitor (IMM) and Public Utility Commission of Texas (PUCT) (reference Section 3.10.4), according to the following:

NOMCR that contains ICCP Data and is submitted ...	***ERCOT shall ...***	***Subject to IMM & PUC Reporting***
Beyond 90 days of the energization date	Allow modification of only ICCP data for an existing NOMCR	No
Between 90 and 15 days prior to the scheduled database load.	Allow modification of only ICCP data for an existing NOMCR	No
Less than 15 days before scheduled database load.	Require a new NOMCR to be submitted containing the ICCP data	Yes

3.10.3 CRR Network Model

(1) ERCOT shall develop models for Congestion Revenue Right (CRR) Auctions that contain, as much as practicable, information consistent with the Network Operations Model. Names of Transmission Elements in the Network Operations Model and the CRR Network Model must be identical for the same physical equipment.

(2) ERCOT shall verify that the names of Hub Buses and Electrical Buses used to describe the same device in any Hub are identically named in both the Network Operations Model and the CRR Network Model.

(3) Each CRR Network Model must include:

(a) A system-wide diagram including all modeled Transmission Elements (except those within Private Use Networks) and Resource Nodes;

(b) Station one-line diagrams for all Settlement Points (indicating the Settlement Point that the Electrical Bus is a part of) and including all Hub Buses used to calculate Hub prices (if applicable), except those within Private Use Networks;

(c) Generation Resource and ESR locations;

(d) Transmission Elements;

(e) Transmission impedances;

(f) Transmission ratings, excluding Relay Loadability Ratings;

(g) Contingency lists;

(h) Data inputs used in the calculation of Dynamic Ratings, and

(i) Other relevant assumptions and inputs used for the CRR Network Model.

(4) ERCOT shall make available to TSPs and/or DSPs and all appropriate Market Participants, consistent with the requirements regarding ECEII set forth in Section 1.3, Confidentiality, the CRR Network Model. ERCOT shall provide model information through the use of the EPRI and NERC-sponsored CIM and web based XML communications or PSS/E format.

3.10.6 QSE and Resource Entity Responsibilities

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation Resource, ESR, SOG, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

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

(1) Resource Entities shall provide Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process, to ERCOT and to TSPs upon request. The Resource Registration data will contain information describing each Generation

Resource, SOG, SOESS, and Load Resource that it represents under Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(2) QSEs shall ensure availability of telemetry to generation and transmission equipment its Resource Entity owns at ERCOT's request to maintain observability and redundancy requirements as specified herein, and under Section 3.10.7.5, Telemetry Requirements. ERCOT shall request such additions when a lack of data telemetry has caused, or can be demonstrated to result in, inaccuracies between Real-Time measurements and modeling outcomes that could result in incorrect LMP prices or potential reliability problems.

(3) For each Generation Resource and Energy Storage Resource (ESR), Resource Entities shall provide ERCOT the following temperature data:

(a) Cold weather temperature limits:

(i) Minimum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without a Forced Outage or Startup Loading Failure due to cold weather after at least one complete winter Peak Load Season following the Resource's Initial Synchronization date based on the previous five calendar years of historical data; and

(ii) Minimum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum rating due to cold weather after at least one complete winter Peak Load Season following the Resource's Initial Synchronization date based on the previous five calendar years of historical data; and

(iii) At least one of the following:

(A) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum sustainable rating; or

(B) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Derate greater than 10 MW and 5% of its winter Seasonal net maximum sustainable rating determined by an engineering analysis; and

(iv) At least one of the following:

(A) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Outage or Startup Loading Failure; or

(B) Minimum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Outage or Startup Loading Failure determined by an engineering analysis.

(b) Hot weather temperature limits:

(i) Maximum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Outage or Startup Loading Failure due to hot weather after at least one complete summer Peak Load Season following the Resource's Initial Synchronization date based on the previous five years of historical data; and

(ii) Maximum historical ambient dry bulb temperature in degrees Fahrenheit at which the Resource has operated without experiencing a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating due to hot weather after at least one complete summer Peak Load Season following the Resource's Initial Synchronization date based on the previous five calendar years of historical data; and

(iii) At least one of the following:

(A) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating; or

(B) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Derate greater than 10 MW and 5% of its summer Seasonal net maximum sustainable rating, determined by an engineering analysis; and

(iv) At least one of the following:

(A) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource was designed to operate without a Forced Outage or Startup Loading Failure; or

(B) Maximum ambient dry bulb temperature in degrees Fahrenheit at which the Resource can operate without a Forced Outage or Startup Loading Failure, determined by an engineering analysis.

(4) Each Resource Entity shall review at least annually the temperatures described in paragraphs (3)(a)(i), (3)(a)(ii), (3)(b)(i), and (3)(b)(ii) above and shall update each Resource's Registration data within 30 days of identifying any change in these temperatures.

(5) Each Resource Entity shall review at least once every seven years the temperatures described in paragraphs (3)(a)(iii), (3)(a)(iv), (3)(b)(iii), and (3)(b)(iv) above and shall update each Resource's Registration data within 30 days of identifying any change in these temperatures.

(6) Resource Entities shall update each Generation Resource's alternate fuel information within 30 days of any changes to the alternate fuel information.

3.10.7.1.4 Transmission, Main Power Transformers (MPTs) and Generation ~~Resource~~ Step-Up Transformers

(1) ERCOT shall model all transformers with a nominal low side (i.e., secondary, not tertiary) voltage above 60 kV.

(2) For Generation Resources and ESRs, ERCOT shall model all Main Power Transformers (MPTs) and Generator Step-Up (GSU) transformers greater than ten MVA to provide for accurate representation of generator voltage control capability including the capability to accept a system operator entry of a specific no-load tap position, or if changeable under Load, accept telemetry of the current tap position.

(3) Each TSP and Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

[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 Resource Entity shall provide ERCOT with information to accurately describe each transformer in the Network Operations Model including any tertiary Load as required by ERCOT. Each TSP, DCTO, and Resource Entity shall provide ERCOT with the following information, subject to the naming conventions in Section 3.10.7.1, Modeling of Transmission Elements and Parameters:

(a) Equipment owner(s);

(b) Equipment operator(s);

(c) The Transmission Element name;

(d) The substation name;

(e) Winding ratings, including Normal Rating, Emergency Rating, 15-Minute Rating, Conductor/Transformer 2-Hour Rating, and Relay Loadability Rating;

(f) Connectivity;

(g) Transformer parameters, including all tap parameters; and

(h) Other data necessary to model Transmission Element(s).

(4) The Resource Entity shall provide parameters for each MPT to ERCOT as part of the Resource Registration data pursuant to Planning Guide Section 6.8.2, Resource Registration Process. ERCOT shall provide the information to TSPs. Each TSP shall coordinate with the operators of the Resources connected to their respective systems to establish the proper transformer tap positions (no-load taps) and the equipment owner shall report any changes to ERCOT using the NOMCR process or other ERCOT prescribed means. Each Resource Entity and each TSP shall schedule generation ~~or Energy Storage System (ESS)~~ Outages at mutually agreeable times to implement tap position changes when necessary. If mutual agreement cannot be reached, then ERCOT shall decide where to set the tap position to be implemented by the Resource Entity at the next generation Outage, considering expected impact on system security, future Outage plans, and participants. TSPs shall provide ERCOT and Market Participants with notice in accordance with paragraph (4) of Section 3.10.4, ERCOT Responsibilities, (except for emergency) prior to the tap position change implementation date.

(5) ERCOT shall post to the MIS Secure Area information regarding all transformers represented in the Network Operations Model.

3.10.7.2 Modeling of Resources and Transmission Loads

Commented [CP4]: Please note NPRR1234 also proposes revisions to this section.

(1) Each Resource Entity shall provide ERCOT and its interconnecting TSP with information describing each of its Generation Resources, ESRs, SOGs, and Load Resources connected to the ERCOT System. All Transmission Generation Resources (TGRs), ESRs connected at transmission voltage, 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, ESRs, Private Use Networks, and Load Resources with their owners to ensure consistency between TSP models and ERCOT models.

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

(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 (TESR) ~~connected at transmission voltage,~~

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) TSPs 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 to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load 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 to facilitate state estimation of Loads that do not telemeter Load measurements. ERCOT shall define "Model Loads", which may be one or more combined Loads, for use in its Network Operations Model. A Model Load 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 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.

3.10.7.6 Use of Generic Transmission Constraints and Generic Transmission Limits

(1) For the sole purpose of creating transmission flow constraints between areas of the ERCOT Transmission Grid in ERCOT applications that are unable to recognize non-thermal operating limits (such as system stability limits and voltage limits on Electrical Buses), ERCOT may create new Generic Transmission Constraints (GTCs) or modify existing GTCs for use in reliability and market analysis. GTCs created or modified as described in this Section shall be used in the SCED application. ERCOT shall not use GTCs in ERCOT applications to replace other constraints already capable of being directly modeled in the SCED application.

(2) During the ERCOT quarterly stability assessment, performed pursuant to Planning Guide Section 5.3.5, ERCOT Quarterly Stability Assessment, if ERCOT determines a GTC is necessary for a new Generation Resource, ESR, ~~and~~or SOTSG due to localized stability issues associated with the output of the interconnecting Generation Resource, ESR, or

SOTSG, the GTL for the GTC shall be set to the lowest non-zero limit for all system conditions outside those in which the limit is zero.

(3) Except as provided in paragraph (6) below, ERCOT shall post a description of each new or modified GTC to the MIS Secure Area as soon as possible, but no later than the day prior to the GTC or GTC modification becoming effective in any ERCOT application. Posting of each new or modified GTC shall include:

(a) The description of the new or modified GTC including the GTL or description of the data and studies used to calculate the GTL associated with each new or modified GTC;

(b) The effective date of the new or modified GTC;

(c) The identity of all constrained Transmission Elements that make up the GTC, including the defined interface where applicable; and

(d) Detailed information on the development of each GTC, including the defined constraint or interface where applicable; and data and studies used for development of each new or modified GTC, including the GTL associated with each new or modified GTC. This information shall be redacted or omitted to protect the confidentiality of certain stability-related GTCs.

(4) Market Participants may review and comment on each new or modified GTC. Within seven days following receipt of any comments, ERCOT shall post the comments to the MIS Secure Area as part of the information related to the subject GTC. ERCOT shall review any comments and may modify any part of a given GTC in response to any comments received.

(5) Anticipated GTLs, except those determined pursuant to paragraph (6) below, shall be posted to the MIS Secure Area no later than one day before the Operating Day.

(6) If an unexpected change to ERCOT System conditions requires the creation of a new GTC or the modification of an existing GTC to manage ERCOT System reliability, and the GTC has not been posted pursuant to paragraph (3) above, ERCOT shall issue an Operating Condition Notice (OCN) and post on the MIS Secure Area the new or modified GTC and its associated GTL(s), including the detailed information described in paragraphs (3) and (5) above. ERCOT shall include an explanation regarding why it did not post the GTC or modification on the previous day.

(7) No later than 180 days after the effective date of a new GTC, ERCOT shall post a report listing alternatives for exiting the GTC to the MIS Secure Area. The listed alternatives may include but are not limited to the implementation or modification of a RAS or a transmission improvement project.

3.10.7.7 DC Tie Limits

(1) ERCOT shall post DC Tie limits for each hour of the Operating Day to the MIS Secure Area no later than 0600 in the Day-Ahead before the Operating Day. ERCOT may update these limits as system conditions change.

(2) DC Tie limits shall be based on expected system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource or ESR shown to be available in its COP will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission constraints resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource or ESR is needed, as well as other system conditions.

[NPRR825: Replace Section 3.10.7.7 above with the following upon system implementation:]

3.10.7.7 DC Tie Advisory Limits

(1) Every hour, ERCOT shall post DC Tie advisory limits for each hour of the next 48 hours to the MIS Secure Area. ERCOT may update these limits as system conditions change. Any updated DC Tie advisory limits shall be posted to the MIS Secure Area as soon as practicable.

(2) DC Tie advisory limits shall be based on expected, or actual system conditions, including Outages, for each hour of the Operating Day and shall be calculated as the lower of the available physical capacity of the DC Tie, the amount of DC Tie import and export that could flow without resulting in transmission security violations that would not be resolved by SCED, or, for the DC Ties with Mexico, any limits supplied by the Mexican system operator. In setting these limits for a given hour, ERCOT shall assume that any Generation Resource or ESR shown to be available in its COP for a given hour will be self-committed or committed at the appropriate time through the Reliability Unit Commitment (RUC) process to resolve any transmission security violations resulting from DC Tie Schedules. DC Tie Schedules are subject to the actual availability of that generation at the time the Generation Resource or ESR is needed, as well as other system conditions.

3.14.1.9 Generation Resource/Energy Storage Resource Status Updates

(1) By April 1st and October 1st of each year and when material changes occur, every Resource Entity that owns or controls a Mothballed Generation Resource, a Mothballed Energy Storage Resource (ESR), or an RMR Unit shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of

returning to service and, in percentage terms, report probable generation capacity from each Resource that the Resource Entity expects to return to service in each Season of each of the next ten years.

(2) For modeling purposes, ERCOT and TSPs shall rely on the most recent submittal of the following two Notifications with respect to an RMR Unit, Mothballed Generation Resource, Mothballed ESR, or Decommissioned Generation Resource: Section 22, Attachment E, Notification of Suspension of Operations, or Section 22, Attachment H, Notification of Change of ~~Generation~~ Resource Designation. Except in the case of an NSO submitted for a ~~Generation~~ Resource temporarily suspending operation due to a Forced Outage, ERCOT shall post each submitted NSO and Notification of Change of ~~Generation~~ Resource Designation to the ERCOT website and issue a Market Notice notifying Market Participants of the posting as soon as practicable, but no later than five Business Days after receipt.

(3) A Mothballed Generation Resource or Mothballed ESR that is not mothballed indefinitely shall remain modeled in all ERCOT systems at all times, (i.e., will not be flagged as "mothballed" in ERCOT's models) and, when it is not available, the Resource Entity shall designate the ~~Generation~~ Resource as on Planned Outage in the Outage Scheduler.

(4) Except for Mothballed Generation Resources and Mothballed ESRs that operate under a Seasonal Operation Period, a Resource Entity with a Mothballed Generation Resource or Mothballed ESR shall notify ERCOT in writing no less than 30 days prior to the date on which the Resource Entity intends to return a Mothballed Generation Resource or Mothballed ESR to service by completing a Notification of Change of ~~Generation~~ Resource Designation.

(5) A Resource Entity must submit a Notification of Change of ~~Generation~~ Resource Designation no later than 60 days prior to the conclusion of an RMR Agreement.

(6) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to begin its Seasonal Operation Period if the first date of operation is prior to the date designated by the Resource Entity in its NSO. A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that operates under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the end date designated by the Resource Entity in its NSO if the Resource Entity intends to suspend operation later than that date. Notifications under this Section shall be provided by the Resource Entity by completing a Notification of Change of ~~Generation~~ Resource Designation form (Section 22, Attachment H).

(7) Once the Resource Entity notifies ERCOT that a Mothballed Generation Resource or Mothballed ESR is operating under a Seasonal Operation Period, the Resource Entity does not need to annually notify ERCOT of such status.

(8) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period shall notify ERCOT in writing no less than 15 days prior to the date on which the Resource Entity intends to return the Mothballed Generation Resource or Mothballed ESR to year-round operation by completing a Notification of Change of ~~Generation~~ Resource Designation form (Section 22, Attachment H).

(9) A Resource Entity with a Mothballed Generation Resource or Mothballed ESR that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section 22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource or Mothballed ESR is to be suspended indefinitely or retired and decommissioned.

(10) ERCOT may request that a Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period be available for operation earlier than June 1st or later than September 30th of any given calendar year. If ERCOT identifies a specific Resource Entity or QSE with which it will discuss such a request in an attempt to reach a mutually agreeable resolution, ERCOT shall issue a Notice as soon as practicable. The Notice shall include the Resource name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, and the potential duration of the extended operation period, including anticipated start and end dates. If agreement is reached for the Mothballed Generation Resource or Mothballed ESR to be available for operation earlier than June 1st or later than September 30th, the Resource Entity shall complete, within two Business Days, a Notification of Change of ~~Generation~~ Resource Designation form (Section 22, Attachment H).

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource or Mothballed ESR operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority.

(12) ERCOT may evaluate, on an annual basis, Mothballed Generation Resources and Mothballed ESRs operating under a Seasonal Operation Period for RMR Service to address ERCOT System reliability during the portion of the year when the Mothballed Generation Resource or Mothballed ESR would be unavailable.

(13) A Resource Entity that submitted an NSO as a result of a Forced Outage must notify ERCOT of its intent to return to service as soon as practicable by updating its status in the Outage Scheduler and Current Operating Plan (COP) and is not required to submit a Notification of Change of ~~Generation~~ Resource Designation.

(14) Before retiring and decommissioning either a Mothballed Generation Resource ~~this~~or Mothballed ESR is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource

Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of ~~Generation~~ Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

(15) If a Generation Resource or Mothballed ESR is designated as decommissioned and retired pursuant to any of the above provisions, ERCOT will permanently remove the ~~Generation~~ Resource from the ERCOT registration systems in accordance with Section 3.10.1. Except as provided in paragraph (16) below, if a Resource Entity decides to bring a Decommissioned Generation Resource back to service at a later date, it will be considered a new Resource and must follow the Generator~~/Energy Storage System~~ Interconnection or Modification (GIM) process detailed in the Planning Guide. If the ~~Generation~~ Resource is designated as mothballed, ERCOT and TSPs will consider the ~~Generation~~ Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.

(16) A Resource Entity may bring a Decommissioned ~~Generation~~ Resource back to service without following the GIM process if the operating characteristics of the Resource are materially identical to the characteristics of the Resource as it existed prior to the date of decommissioning and the Resource Entity submits a Notification of Change of ~~Generation~~ Resource Designation (Section 22, Attachment H) within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. The date of return proposed in the Notification must be a Network Operations Model load date that is no earlier than 45 days and no later than 180 days from the date of the Resource Entity's Notification. ERCOT may delay the Network Operations Model load date based on the timing of the Resource Entity's submission of complete Resource registration data. If the Resource Entity is not the Resource Entity that was associated with the Generation Resource at the time it was removed from the model, the Resource Entity shall provide ERCOT documentation that establishes the Resource Entity's ownership of the Generation Resource.

(a) Notwithstanding the proposed date of return reflected in the Notification, as a condition for the synchronization of the Resource, ERCOT or the interconnecting Transmission and/or Distribution Service Provider (TDSP) may require any studies, testing, metering, or facility upgrades that ERCOT or the TDSP deem necessary for the reliable interconnection of the Resource, and ERCOT may require the Resource Entity to resolve any operational concern associated with the Resource. The TDSP may require the Resource Entity to compensate the TDSP for any required studies or upgrades in the same manner contemplated for new Generation Resources by the ERCOT Planning Guide, the TDSP's tariff, and the Standard Generation Interconnection Agreement (SGIA).

(b) If ERCOT or the TDSP requires any studies, testing, metering or facility upgrades, or if ERCOT determines that operational concerns must be addressed, the Resource Entity must complete the commissioning process within 90 days of the date of synchronization, subject to any extension authorized by ERCOT for good cause.

(c) Any ~~Generation~~ Resource that returns to service pursuant to this paragraph is entitled to any exemption from ERCOT requirements that the Resource was entitled to at the time it was removed from the model if the exemption still exists under ERCOT rules.

[NPRR885, NPRR995, and NPRR1007: Insert applicable portions of Sections 3.14.4 and 3.14.4.1 below upon system implementation for NPRR885 or NPRR995; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007:]

3.14.4 Must-Run Alternative Service

3.14.4.1 Overview and Description of MRAs

(1) Subject to approval by the ERCOT Board, ERCOT may procure Must-Run Alternative (MRA) Service as an alternative to contracting with an RMR Unit if ERCOT determines that the MRA Agreement(s) will, in whole or in part, address the reliability need identified in the RMR study in a more cost-effective manner.

(2) ERCOT will issue a request for proposal (RFP) to solicit offers from QSEs to provide MRA Service.

(a) A QSE may submit an offer in response to the RFP or enter into an MRA Agreement only if it meets all registration and qualification criteria in Section 16.2, Registration and Qualification of Qualified Scheduling Entities.

(b) QSEs whose offers for MRA Service are accepted will be paid according to their offers, subject to the terms of the RFP, MRA Agreement and ERCOT Protocols. A clearing price mechanism shall not be used for awarding offers for MRA Service.

(c) A QSE may submit more than one offer for MRA Service in response to a single RFP. A QSE may not submit the same MRA or MRA Sites in more than one of its offers. ERCOT may award multiple offers to a QSE, so long as the MRA or MRA Sites in an awarded offer are not included in any other awarded offer. A QSE may condition ERCOT's acceptance of an offer for a Demand Response MRA on ERCOT's acceptance of an offer for a co-located Other Generation MRA offer.

(d) Demand Response MRAs and Other Generation MRAs, including MRA Sites within aggregated MRAs, that are situated in NOIE service territories, are eligible to provide MRA Service. Any QSE other than the NOIE QSE wishing to represent such MRAs must obtain written authorization allowing the representation from the NOIE in which the MRA is located. This authorization must be signed by an individual with authority to bind the NOIE and must be submitted to ERCOT prior to the submission of an offer in response to the MRA.

(3) An MRA may be connected at either transmission or distribution voltage.

(4) An MRA offer is ineligible to the extent it offers capacity that was included as a Resource in ERCOT's RMR analysis or in the Load forecasts from the Steady State Working Group (SSWG) base cases used as the basis for the RMR analysis, as provided for in paragraph (3)(a) of Section 3.14.1.2, ERCOT Evaluation Process.

(5) Each MRA must provide at least five MW of capacity.

(6) Eligible MRA resources may include:

(a) A proposed Generation Resource or Energy Storage Resource (ESR) that was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Proposed Generation Resources or ESRs must adhere to all interconnection requirements, including the requirements of Planning Guide Section 5, Generator Interconnection or Modification.

(ii) If the proposed Generation Resource is an Intermittent Renewable Resource (IRR), the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the MRA Contracted Hours.

(b) Proposed capacity additions to existing Generation Resources or ESRs, if the additional capacity was not included in the reliability need evaluation pursuant to paragraph (3)(a) of Section 3.14.1.2.

(i) Prior to providing MRA Service, the Resource Entity will be required to modify its Resource Registration information and complete necessary ~~Generator~~ interconnection requirements with respect to this additional capacity.

(ii) If the capacity is being added to an IRR, the QSE shall provide capacity values based on the Resource's projected peak average capacity contribution during the hours identified during the MRA Contracted Hours.

(c) A proposed or existing generator registered, or proposed to be registered, with ERCOT as a Settlement Only Generator (SOG) or as Distributed Generation (DG). If the generator is an intermittent renewable generator, the QSE, when responding to an RFP for MRA Service, shall provide capacity values based on the MRA's projected peak average capacity contribution during the hours identified in the MRA Contracted Hours.

(d) Proposed or existing Demand response assets, which may include Load Resources and ERS Loads.

(c) A proposed or existing Energy Storage System (ESS) registered, or proposed to be registered, with ERCOT as a Settlement Only Energy Storage System (SOESS).

(7) An MRA must be able to provide power injection or Demand response to the ERCOT System at ERCOT's discretion during the MRA Contracted Hours.

(a) QSE offers in response to an RFP for MRA Service must fully describe all of the MRA's temporal constraints.

(b) For a Demand Response MRA, QSE offers in response to an RFP for MRA Service must include a statement as to whether the offered capacity is a Weather-Sensitive MRA.

(8) The QSE representing an MRA must be capable of receiving both VDI and XML instructions.

(9) ERCOT will periodically validate an MRA's telemetry using 15-minute interval meter data.

(10) An MRA for which the MRA or every MRA Site, is metered with either an Advanced Meter or an ERCOT-Polled Settlement (EPS) Meter must be available for qualification testing no later than 10 days prior to the first day of the contracted MRA Service. Other MRAs must be available for qualification testing no later than 45 days prior to the first day of the contracted MRA Service.

(11) All MRA Sites within an MRA must be of the same type (i.e., all Generation Resource MRA, ESR MRA, Other Generation MRA, or Demand Response MRA).

(12) A QSE representing an MRA shall submit to ERCOT and continuously update an Availability Plan for each MRA Contracted Hour for the current Operating Day and the next six Operating Days.

(13) A QSE representing an MRA or MRA Site may not submit DAM Offers, provide an Ancillary Service or carry an ERS responsibility on behalf of any MRA or MRA Site during the MRA Contracted Hours. Demand Response MRAs may not participate in TDSP standard offer programs during any MRA Contracted Hours.

(14) A Combined Cycle Train serving as an MRA must be configured as a single Combined Cycle Generation Resource.

(15) QSEs representing MRAs shall submit offers using an MRA offer sheet as provided by ERCOT.

(16) QSEs must submit the following information for each MRA offer:

(a) The capacity, months and hours offered;

(b) For an aggregated MRA, the offered capacity allocated to each MRA Site for all months and hours offered;

(c) The Resource ID, ESI ID and or unique meter ID associated with the MRA, or in the case of an aggregated MRA, a list of the Resource IDs, ESI IDs and/or unique meter IDs of the offered MRA Sites;

(d) The MRA Standby Price, represented in dollars per MW per hour;

(e) Required capital expenditure, if any, if the MRA offer is awarded;

(f) The MRA Event Deployment Price, in dollars per deployment event, or proxy fuel consumption rate;

(g) The ramp period or startup time of the MRA or aggregated MRA;

(h) The MRA Variable Price, in dollars per MW per hour, and/or proxy heat rate;

(i) The target availability of the MRA or aggregated MRA; and

(j) Any additional information required by ERCOT within the RFP.

(17) Demand Response MRAs shall not be deployed more than once per Operating Day.

(18) Except for a Forced Outage, any Outage of an MRA must be approved by ERCOT.

(19) For any MRA that is registered with ERCOT as a Resource, the QSE representing the MRA must be the same as the QSE representing the Resource.

[NPRR885: Insert Section 3.14.4.5 below upon system implementation:]

3.14.4.5 Standards for Generation Resource MRAs and ESR MRAs

(1) A Generation Resource MRA and ESR MRA shall at all times communicate accurate Resource Status to ERCOT via telemetry as described in Section 6.4.6, Resource Status.

(2) A Generation Resource MRA and ESR MRA shall be committed by ERCOT VDI and Dispatched by SCED.

[NPRR885: Insert Section 3.14.4.7 below upon system implementation:]

3.14.4.7 MRA Testing

(1) ERCOT shall conduct a test of every MRA prior to the initial MRA Contracted Month.

(2) ERCOT may conduct an unannounced test of any MRA at any time during a MRA Contracted Month. Testing for MRAs, other than for Demand Response MRAs classified as providing Weather-Sensitive MRA, will be limited to no more than once per MRA Contracted Month. Testing for Demand Response MRAs classified as Weather-Sensitive MRA will be limited to no more than twice per MRA Contracted Month.

(3) ERCOT will not conduct an unannounced test of an MRA during a calendar month subsequent to an actual MRA deployment event.

(4) A substituted Demand Response MRA or Other Generation MRA will be subject to monthly unannounced testing regardless of tests or events occurring prior to the start date of the substitution.

(5) ERCOT shall limit the duration of MRA deployment periods of any single test to a maximum of one hour.

(6) For the purposes of Section 6.6.6.7, MRA Standby Payment, ERCOT may adjust the testing capacity results for a Generation Resource MRA or an ESR MRA to reflect conditions beyond the control of the Generation Resource MRA or ESR MRA.

3.17.1 Regulation Service

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or Energy Storage Resource (ESR) in discharge mode providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. Fast Responding Regulation Up Service (FRRS-Up) is a subset of Reg-Up Service in which the participating Resource provides Reg-Up capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal. The LFC signal for FRRS-Up is separate from the LFC signal for other Reg-Up.

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) Regulation Up Service (Reg-Up) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Up capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper

system frequency. A Generation Resource or Energy Storage Resource (ESR) in discharge mode providing Reg-Up must be able to increase energy output when deployed and decrease energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Up must be able to decrease Load when deployed and increase Load when recalled. ERCOT dispatches Reg-Up by a Load Frequency Control (LFC) signal.

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or ESR in discharge mode providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. Fast Responding Regulation Down Service (FRRS-Down) is a subset of Reg-Down Service in which a participating Resource provides Reg-Down capacity to ERCOT within 60 cycles of either its receipt of an ERCOT Dispatch Instruction or the detection of a trigger frequency independent of an ERCOT Dispatch Instruction. ERCOT dispatches Reg-Down by an LFC signal. The LFC signal for FRRS-Down is separate from the LFC signal for other Reg-Down.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) Regulation Down Service (Reg-Down) is a service that provides capacity that can respond to signals from ERCOT within five seconds to respond to changes from scheduled system frequency. The amount of Reg-Down capacity is the amount of capacity available from a Resource that may be called on to change output as necessary to maintain proper system frequency. A Generation Resource or ESR in discharge mode providing Reg-Down must be able to decrease energy output when deployed and increase energy output when recalled. A Load Resource or ESR in charge mode providing Reg-Down must be able to increase Load when deployed and decrease Load when recalled. ERCOT dispatches Reg-Down by an LFC signal.

3.17.2 Responsive Reserve Service

Commented [CP5]: Please note NPRR1260 also proposes revisions to this section.

(1) Responsive Reserve (RRS) is a service used to restore or maintain the frequency of the ERCOT System in response to a significant frequency deviation.

(2) RRS is automatically self-deployed by Resources in a manner that results in real power increases or decreases.

(3) RRS may be provided by:

(a) On-Line Generation Resource capable of providing Primary Frequency Response with the capacity excluding Non-Frequency Responsive Capacity (NFRC);

(b) Resources capable of providing Fast Frequency Response (FFR) and sustaining their response for up to 15 minutes;

(c) Load Resources controlled by high-set under-frequency relays; ~~and~~

(d) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides;~~.~~ and

(e) ESRs.

3.17.3 Non-Spinning Reserve Service

(1) Non-Spinning Reserve (Non-Spin) is provided by using:

(a) Generation Resources, whether On-Line or Off-Line, capable of:

(i) Being synchronized and ramped to a specified output level within 30 minutes; and

(ii) Running at a specified output level for at least four consecutive hours;

(b) Controllable Load Resources qualified for Dispatch by Security-Constrained Economic Dispatch (SCED) and capable of:

(i) Ramping to an ERCOT-instructed consumption level within 30 minutes; and

(ii) Consuming at the ERCOT-instructed level for at least four consecutive hours;~~ or~~

(c) Load Resources that are not Controllable Load Resources and are qualified for deployment by the operator using the Ancillary Service Deployment Manager and capable of:

(i) Reducing consumption based on an ERCOT Extensible Markup Language (XML) instruction within 30 minutes; and

(ii) Maintaining that deployment until recalled;~~.~~ or

(d) ESRs.

(2) The Non-Spin may be deployed by ERCOT to increase available reserves in Real-Time Operations.

3.17.4 ERCOT Contingency Reserve Service

(1) ERCOT Contingency Reserve Service (ECRS) is a service that is provided using capacity that can be sustained at a specified level for two consecutive hours and is used to restore or maintain the frequency of the ERCOT System:

(a) In response to significant depletion of RRS;

(b) As backup Regulation Service; and

(c) By providing energy to avoid getting into or during an Energy Emergency Alert (EEA).

(2) ECRS may be provided through one or more of the following means:

(a) From On-Line or Off-Line Resources as prescribed in the Operating Guides following a significant frequency deviation in the ERCOT System; and

(b) Either manually or by using a four-second signal to provide energy on deployment by ERCOT.

(3) ECRS may be used to provide energy prior to or during the implementation of an EEA. ECRS provides Resource capacity, or capacity from interruptible Load available for deployment on ten minutes' notice.

(4) ECRS may be provided by:

(a) Unloaded, On-Line Generation Resource capacity;

(b) Quick Start Generation Resources (QSGRs);

(c) Load Resources that may or may not be controlled by high-set, under-frequency relays;

(d) Controllable Load Resources; ~~and~~

(e) Generation Resources operating in synchronous condenser fast-response mode as defined in the Operating Guides; and

(f) ESRs.

3.18 Resource Limits in Providing Ancillary Service

Commented [CP6]: Please note NPRRs 1235 and 1257 also propose revisions to this section.

(1) For ~~both~~ Generation Resources, Energy Storage Resources (ESRs), and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific designation of capacity to provide Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), and Non-Spinning Reserve (Non-Spin).

[NPRR1007: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) For both Generation Resources and Load Resources the High Sustained Limit (HSL) must be greater than or equal to the Low Sustained Limit (LSL) and the sum of the Resource-specific awards for Responsive Reserve (RRS), ERCOT Contingency Reserve Service (ECRS), Regulation Up Service (Reg-Up), Regulation Down Service (Reg-Down), and Non-Spinning Reserve (Non-Spin).

(2) For Non-Spin, the amount of Non-Spin provided must be less than or equal to the HSL for Off-Line Generation Resources.

[NPRR1007: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) For Non-Spin, the amount of Non-Spin awarded must be less than or equal to the HSL for Off-Line Generation Resources.

(3) For RRS:

(a) The full amount of RRS awarded to or self-arranged from an On-Line Generation Resource or ESR is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource and ESR subject to verified droop performance. The default value for any newly qualified Generation Resource or ESR shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;

(b) Generation Resources operating in the synchronous condenser fast-response mode may provide RRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz. Once deployed, a Resource telemetering a Resource Status of ONRR shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled by ERCOT after frequency recovers above 59.98 Hz, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility;

(c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and

(d) The amount of RRS provided from a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated

capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz. A Resource providing RRS as FFR that is deployed shall not recall its capacity until system frequency is greater than 59.98 Hz. Once deployed, a Resource telemetering a Resource Status of ONFFRRRS or ONFFRRRSL shall telemeter an RRS Ancillary Service Schedule of zero, and when recalled, such Resource shall telemeter an RRS Ancillary Service Schedule that shall be a non-zero value equal to its RRS Ancillary Service Responsibility. Once recalled, a Resource providing RRS as FFR must restore its full RRS Ancillary Service Resource Responsibility within 15 minutes after cessation of deployment or as otherwise directed by ERCOT.

[NPRR1007: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) For RRS:

(a) The full amount of RRS that can be provided by an On-Line Generation Resource or ESR is dependent upon the verified droop characteristics of the Resource. ERCOT shall calculate and update, using the methodology described in the Nodal Operating Guide, a maximum MW amount of RRS for each Generation Resource and ESR subject to verified droop performance. The default value for any newly qualified Generation Resource or ESR shall be 20% of its HSL. A Private Use Network with a registered Resource may use the gross HSL for qualification and establishing a limit on the amount of RRS capacity that the Resource within the Private Use Network can provide;

(b) Generation Resources operating in the synchronous condenser fast-response mode may be awarded RRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz;

(c) The initiation setting of the automatic under-frequency relay setting for Load Resources providing RRS shall not be lower than 59.70 Hz; and

(d) The amount of RRS awarded to a Resource capable of providing Fast Frequency Response (FFR) must be less than or equal to its 15-minute rated capacity. The initiation setting of the automatic self-deployment of the Resource providing RRS as FFR must be no lower than 59.85 Hz.

(4) For ECRS:

(a) The full amount of ECRS provided from an On-Line Generation Resource or ESR must be less than or equal to ten times the Emergency Ramp Rate;

(b) The full amount of ECRS provided by a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as

demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;

(c) Generation Resources operating in the synchronous condenser fast-response mode may provide ECRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz, and

(d) For any Load Resources controlled by under-frequency relay and providing ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays.

[NPRR1007: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) For ECRS:

(a) The full amount of ECRS that can be awarded to an On-Line Generation Resource must be less than or equal to ten times the Emergency Ramp Rate;

(b) The full amount of ECRS that can be awarded to a Quick Start Generation Resource (QSGR) must be less than or equal to its proven ten-minute capability as demonstrated pursuant to paragraph (16) of Section 8.1.1.2, General Capacity Testing Requirements;

(c) Generation Resources operating in the synchronous condenser fast-response mode may be awarded ECRS up to the Generation Resource's proven 20-second response capability (which may be 100% of the HSL). The initiation setting of the automatic under-frequency relay setting shall not be lower than 59.80 Hz; and

(d) For any Load Resources controlled by under-frequency relay and awarded ECRS, the initiation setting of the automatic under-frequency relay setting shall not be lower than 59.70 Hz. To provide ECRS, Load Resources are not required to be controlled by under-frequency relays.

3.22.1.2 Generation Resource or Energy Storage Resource Interconnection Assessment

Commented [CP7]: Please note NPRR1234 also proposes revisions to this section.

(1) In the security screening study for a Generation Resource/Energy Storage Resource Interconnection or Change Request, ERCOT will perform a topology-check and determine if the Generation Resource or Energy Storage Resource (ESR) will become radial to a 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 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 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 SSR 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 SSR 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 SSR 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 SSR Protection in lieu of SSR Mitigation, as required by paragraph (3) above, if:

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

(ii) The SSR Protection is approved by ERCOT; and

(iii) The Generation Resource or ESR installs the ERCOT-approved SSR 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 SSR 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 SSR 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

Commented [CP8]: Please note NPRR1234 also proposes revisions to this section.

(1) For any proposed Transmission Facilities connecting to or operating at 345 kV, the TSP shall perform an SSR vulnerability assessment, including a topology-check and/or frequency scan assessment in accordance with Section 3.22.2, Subsynchronous Resonance 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 SSR assessment for ERCOT's review. For the purposes of this Section, a Generation Resource or 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 ESR or a Generation Resource or ESR satisfying Planning Guide Section 6.9 at the time the transmission project is proposed to become vulnerable to SSR, ERCOT shall perform an SSR 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 SSR 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 SSR assessment to confirm or refute the SSR vulnerability.

(4) 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.

(5) If the SSR study confirms a Generation Resource or ESR is vulnerable to SSR in the event of four or less 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 SSR Mitigation on the ERCOT transmission system. The SSR 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 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) 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 Annual SSR Review

Commented [CP9]: Please note NPRR1234 also proposes revisions to this section.

(1) ERCOT shall perform an SSR 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 SSR 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 or ESR will become radial to series capacitors(s) in the event of less than 14 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 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 SSR Mitigation on the ERCOT transmission system. The SSR 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.

3.22.2 Subsynchronous Resonance Vulnerability Assessment Criteria

Commented [CP10]: Please note NPRR1234 also proposes revisions to this section.

(1) A Generation Resource or ESR is considered to be potentially vulnerable to SSR in the topology-check if athe Generation Resource or ESR will become radial to a series capacitors(s) in the event of less than 14 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) 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.

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

(a) The 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) The oscillation, if occurred, is not damped; or

(c) The oscillation, if occurred, results in disconnection of any transmission and generation facilities.

3.22.3 Subsynchronous Resonance Monitoring

Commented [CP11]: Please note NPRR1234 also proposes revisions to this section.

(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 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 SSR 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 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 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 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~~is~~ at least three contingencies away from SSR vulnerability.

4.4.6.3 PTP Obligations with Links to an Option DAM Award Eligibility

(1) A bid for a PTP Obligation with Links to an Option will not be considered eligible for award for an Operating Hour if it sources at a Resource Node where ~~the~~a Generation Resource or Energy Storage Resource (ESR) has a COP Resource Status of:

(a) OUT for an Operating Hour, or

(b) OFF for an Operating Hour, and

(i) The QSE representing the Resources has not submitted a valid Three-Part Supply Offer or Ancillary Service Offer to be considered by the DAM; and

(ii) The QSE representing the Resource has not submitted a valid Energy Only Offer at any Resource Node associated with the Resource.

(2) Where more than one Generation Resource or ESR is associated with a Resource Node, ERCOT will consider a PTP Obligation with Links to an Option bid eligible for award unless all Generation Resources and ESRs associated with the Resource Node do not satisfy the COP Resource Status requirements in paragraph (1) above during the Operating Hour.

(3) In order for ERCOT to award a bid for a PTP Obligation with Links to an Option under this section for an upcoming year, by October 1 of the prior year a NOIE must have provided ERCOT with an attestation that the Generation Resource or ESR for the Resource Node where the bid is sourced is owned or controlled by the NOIE, or has a contractual commitment for capacity and/or energy with the NOIE. The attestation must be executed by an officer or executive with authority to bind the NOIE, and submitted to ERCOT. ERCOT shall rely exclusively on the attestation provided by a NOIE in determining eligibility for bid awards under this section. ERCOT shall issue a Market Notice by September 1 of each year reminding NOIEs of the October 1 deadline for submitting attestations for the upcoming year.

4.4.7.1 Self-Arranged Ancillary Service Quantities

Commented [CP12]: Please note NPRR1235 also proposes revisions to this section.

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 100 MW of ERCOT Contingency Reserve Service (ECRS), 100 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 50 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding Ancillary Service Obligation, provided that the amount self-arranged from the QSE's Resources for a given Ancillary Service shall not exceed the amount of the QSE's Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE's Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Services Market (SASM), as applicable, for $0/MWh.

[NPRR1091: Replace paragraph (1) above with the following upon system implementation:]

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the Ancillary Service Obligation allocated to it by ERCOT. QSEs may not self-arrange Regulation Service amounts that include Fast Responding Regulation Up Service (FRRS-Up) or Fast Responding Regulation Down Service (FRRS-Down) quantities. In addition, a QSE may self-arrange up to 150 MW of Responsive Reserve (RRS), 25 MW of Regulation Up Service (Reg-Up), 25 MW of Regulation Down Service (Reg-Down), and 300 MW of Non-Spinning Reserve (Non-Spin) in excess of its corresponding

Ancillary Service Obligation, provided that the amount self-arranged from the QSE's Resources for a given Ancillary Service shall not exceed the amount of the QSE's Ancillary Services Obligation for that Ancillary Service. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its Ancillary Service Obligation. Any Self-Arranged Ancillary Service Quantities in excess of a QSE's Ancillary Service Obligation will be considered to be offered in the DAM or Supplemental Ancillary Services Market (SASM), as applicable, for $0/MWh.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation or upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) For each Ancillary Service, a QSE may self-arrange all or a portion of the advisory Ancillary Service Obligation allocated to it by ERCOT, subject to the QSE's share of system-wide limits as established by Section 3.16, Standards for Determining Ancillary Service Quantities. If a QSE elects to self-arrange Ancillary Service capacity, then ERCOT shall not pay the QSE for the Self-Arranged Ancillary Service Quantities for the portion that meets its final Ancillary Service Obligation; ERCOT shall pay the QSE the respective Day-Ahead Ancillary Service price for any Self-Arranged Ancillary Service Quantities that exceed a QSE's final Ancillary Service Obligation.

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, needs to be obtained through the DAM.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) The QSE must indicate before 1000 in the Day-Ahead the Self-Arranged Ancillary Service Quantities, by service, so ERCOT can determine how much Ancillary Service capacity, by service, remains to be obtained based on DAM offers and associated Ancillary Service Demand Curves (ASDCs).

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities unless ERCOT opens a SASM.

[NPRR1008: Replace paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(3) At or after 1000 in the Day-Ahead, a QSE may not change its Self-Arranged Ancillary Service Quantities.

(4) Before 1430 in the Day-Ahead, all Self-Arranged Ancillary Service Quantities must be represented by physical capacity, either by Generation Resources, ESRs, or Load Resources, or backed by Ancillary Service Trades.

(5) The QSE may self-arrange Reg-Up, Reg-Down, ECRS, RRS, and Non-Spin.

(6) The QSE may self-arrange Ancillary Services from one or more Resources it represents and/or through an Ancillary Service Trade.

(7) The additional Self-Arranged Ancillary Service Quantity specified by the QSE in response to a SASM notice by ERCOT to obtain additional Ancillary Services in the Adjustment Period cannot be more than 100 MW of ECRS, 100 MW of RRS, 25 MW of Reg-Up, 25 MW of Reg-Down, and 50 MW of Non-Spin greater than the additional Ancillary Service amount allocated by ERCOT to that QSE, as stated in the SASM notice, and cannot be changed once committed to ERCOT.

(8) If a QSE does not self-arrange all of its Ancillary Service Obligation, ERCOT shall procure the remaining amount of that QSE's Ancillary Service Obligation.

[NPRR1008: Replace paragraphs (7) and (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

(7) A QSE shall not submit Ancillary Services trades that result in the QSE's purchased quantities of Ancillary Services exceeding the QSE's Self-Arranged Ancillary Service Quantities.

(a) At 1430 in the Day-Ahead, ERCOT shall post a report on the MIS Certified Area to notify the QSE if there is an overage in the QSE's purchased quantities of Ancillary Services in violation of the above limitation.

(b) If the QSE has such an overage as of the end of the Adjustment Period, that QSE will be charged for any quantity that exceeds their Self-Arranged Ancillary Service Quantities per Section 6.7.5.1, Real-Time Ancillary Service Imbalance Payment or Charge.

(9) For self-arranged RRS, the QSE shall indicate the quantity of the service that is provided from:

(a) Resources providing Primary Frequency Response;

(b) Load Resources controlled by high-set under-frequency relays; and

(c) Fast Frequency Response (FFR) Resources.

(10) For self-arranged ECRS, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched and those that are SCED-dispatchable.

[NPRR1213: Replace paragraph (10) above with the following upon system implementation, and upon system implementation of NPRR1171:]

(10) For self-arranged ECRS and Non-Spin, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) on circuits subject to Load shed, and Resources that are SCED-dispatchable not on circuits subject to Load shed.

(11) For self-arranged Non-Spin, the QSE shall indicate the quantity of the service that is provided from Resources that are manually dispatched, DGRs and DESRs on circuits subject to Load shed, and Resources that are SCED-dispatchable and not on circuits subject to Load shed.

4.4.7.3 Ancillary Service Trades

Commented [CP13]: Please note NPRR1235 also proposes revisions to this section.

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity between a buyer and a seller.

[NPRR1008: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) An Ancillary Service Trade is the information for a QSE-to-QSE transaction that transfers an obligation to provide Ancillary Service capacity or purchase Ancillary Services in the Real-Time Market (RTM) between a buyer and a seller.

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Supply Responsibility of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

[NPRR1008: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) An Ancillary Service Trade that is reported to ERCOT by 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in the DRUC process. An Ancillary Service Trade that is reported to ERCOT after 1430 in the Day-Ahead changes the Ancillary Service Position of the buyer and seller in any applicable HRUC process, the deadline for which is after the trade is submitted.

(3) As soon as practicable, ERCOT shall notify each QSE through the Messaging System of any of its Ancillary Service Trades that are invalid Ancillary Service Trades. The QSE may correct and resubmit any invalid Ancillary Service Trade, but the reporting time of the trade is determined by when the validated Ancillary Service Trade was submitted and not when the original invalid Ancillary Service Trade was submitted.

(4) A QSE with an Ancillary Service Supply Responsibility for ECRS, originally designated to be provided by a Generation Resource, may transfer its responsibility via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a Generation Resource.

[NPRR1008: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a ~~Generation~~SCED-dispatchable Resource, may transfer that portion of its Ancillary Service Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by a ~~Generation~~SCED-dispatchable Resource.

[NPRR1213: Delete paragraph (4) above upon system implementation, and upon system implementation of NPRR1171, and renumber accordingly.]

(5) A QSE with an Ancillary Service Supply Responsibility for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer its responsibility via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either:

[NPRR1008: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(5) A QSE with an Ancillary Service Position for ECRS, originally designated to be provided by a Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz, may transfer that portion of its Ancillary Service

Position via Ancillary Service Trade(s) to another QSE only if that QSE designates the ECRS will be provided by either:

(a) A Generation Resource;

(b) An ESR; or

(cb) A Load Resource providing ECRS triggered with or without under-frequency relays set at 59.70 Hz.

[NPRR1213: Delete paragraph (5) above upon system implementation, and upon system implementation of NPRR1171, and renumber accordingly.]

(6) The table below shows the ECRS trades that are allowed for each type of original responsibility:

	Allowable ECRS Ancillary Service Trades	
Original Responsibility	**SCED-dispatchable ECRS**	**Manually dispatched ECRS**
SCED-dispatchable ECRS	Yes	No
Manually dispatched ECRS	Yes	Yes

[NPRR1213: Replace paragraph (6) above with the following upon system implementation, and upon system implementation of NPRR1171:]

(4) The table below shows the ECRS trades that are allowed for each type of original responsibility:

	Allowable ECRS Ancillary Service Trades		
Original Responsibility	**SCED-dispatchable ECRS not from DGRs and DESRs on a Load shed circuit**	**SCED-dispatchable ECRS from DGRs and DESRs on a Load shed circuit**	**Manually dispatched ECRS**