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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 June 18, 2024, the ERCOT Board of Directors (Board) recommended Commission approval of the following proposed revisions to the ERCOT rules (Revision Requests) (Nodal Protocol Revision Requests (NPRRs), Nodal Operating Guide Revision Requests (NOGRRs) and Planning Guide Revision Requests (PGRRs)):

- NPRR1198, Congestion Mitigation Using Topology Reconfigurations;
- NPRR1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID;
- NPRR1218, REC Program Changes Per P.U.C. Subst. R. 25.173, Renewable Energy Credit Program;
- NPRR1220, Market Restart Approval Process Modifications;
- NPRR1222, Public Utility Commission of Texas Approval of the Methodology for Determining Ancillary Service Requirements;
- NPRR1223, Addition of TA Contact Information Into TDSP Application Form;
- NPRR1224, ECRS Manual Deployment Triggers;
- NPRR1228, Continued One-Winter Procurements for Firm Fuel Supply Service (FFSS);
- NOGRR255, High Resolution Data Requirements;
- NOGRR258, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations;
- PGRR112, Dynamic Data Model and Full Interconnection Study (FIS) Deadline for Quarterly Stability Assessment;

- PGRR113, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations; and
- PGRR114, Related to NPRR1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID.

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: June 21, 2024

Respectfully submitted,

/s/ Jonathan Levine

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ATTORNEYS FOR ELECTRIC RELIABILITY COUNCIL OF TEXAS, INC.

Board Report

NPRR Number	1198	NPRR Title	Congestion Mitigation Using Topology Reconfigurations
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Between $50k and $80k; Between $180k and $220k (Annual Recurring O&M) Project Duration: 4 to 7 months	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Priority – 2025; Rank – 4520	
Nodal Protocol Sections Requiring Revision		2.1, Definitions 3.10.7.4, Remedial Action Schemes, Automatic Mitigation Plans and Remedial Action Plans 6.5.1.1, ERCOT Control Area Authority	
Related Documents Requiring Revision/Related Revision Requests		Nodal Operating Guide Revision Request (NOGRR) 258, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations Planning Guide Revision Request (PGRR) 113, Related to NPRR1198, Congestion Mitigation Using Topology Reconfigurations	
Revision Description		This Nodal Protocol Revision Request (NPRR) defines Extended Action Plan (EAP), adds EAP as a type of Constraint Management Plan (CMP) suitable for managing congestion that is resolvable by Security-Constrained Economic Dispatch (SCED), and removes language limiting the application of EAPs to congestion issues for which there exists no feasible SCED. The related NOGRR258 proposes changes that add language to allow the use of EAPs to address congestion that is resolvable by SCED, adds guardrails to ensure that topology reconfiguration requests meet basic reliability and economic criteria, and defines the process for submission, review, and approval of EAPs. This NPRR and NOGRR258 leverage ERCOT's existing CMP process to quickly mitigate critical transmission congestion impacts by establishing a scalable process for topology reconfiguration	

	requests that is transparent, predictable, equitable, workable, reliable, and compatible with existing planning processes. ERCOT already leverages topology optimization in the CMP processes. Since NPRR529, Constraint Management Plan, was introduced in 2013 with the limitations that this NPRR proposes to revise, the power industry has evolved and there have been technological improvements that make transmission topology reconfigurations a powerful option to mitigate congestion beyond just use cases for which there is no feasible SCED solution.
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	Transmission congestion in ERCOT has been increasing. The Real-Time congestion value for 2022 was $2.8B, which exceeded the $2.1B for the full year 2021, even accounting for impacts from Winter Storm Uri. Congestion has major impacts on grid reliability, electricity costs, and open access. All Market Participants are affected. The proposed revisions aim to make the best use possible of the ERCOT Transmission Grid to mitigate congestion and its impacts. Grid topology optimization finds network reconfiguration options to re-route power flows around bottlenecks. Solutions validated by the System Operator can be rapidly implemented using existing circuit breaker equipment. Several other regions (e.g., Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP)) currently endorse reconfiguration actions for congestion mitigation and impacts have been overwhelmingly positive. The use of optimal reconfigurations in those regions has demonstrated

	significant economic and reliability benefits such as 10% transfer capacity increase for major thermal constraints, 40% reduction in congestion costs, 70% reduction in the frequency of constraint overloads, and mitigation of transmission bottlenecks; thus, increasing generation deliverability, improving resource adequacy, and providing resilience benefits. In the context of CMPs, topology reconfigurations are effective, inexpensive, and low-risk. Prior to wholesale competition, Texas utilities made extensive use of topology reconfigurations to mitigate congestion for generation deliverability. The original mathematical formulation for SCED includes transmission topology as an input for price formation. Reconfigurations are a latent feature of the market design; thus, their application is not at all “out-of-market". When SCED was first implemented, there was no known method to identify optimal network topologies in operational time scales. Computational advances have now reduced the time required for solution identification to just a few seconds. The EAPs outlined in this NPRR can be proposed by ERCOT or any Market Participant to implement a switching solution for a set period of time. The solution is approved by ERCOT, impacted generators, and Transmission Operators (TOs). A detailed list of guardrails is applied to ensure that the solution is reliable, workable, and transparent. As topology optimization is a technological reality, to delay its natural implementation would distort price signals and mislead investors. This NPRR and NOGRR258 were developed jointly with ERCOT Staff to ensure that these operational capabilities are implemented in a manner that meets the following criteria: **Transparency.** The EAP process is transparent - reconfiguration plans are published and Market Participants can comment on them. The information and software required to identify reconfiguration solutions and their impacts are available to all Market Participants. **Predictability.** Congestion patterns and their impacts are generally well known and changes can be anticipated by Market Participants. Approval criteria can be established such that expectations are clear and consistent. Reconfigurations can easily be reversed. EAPs have pre-determined beginning and ending times that make the impact or reconfigurations easily predictable by any Market Participant. **Equity.** The choices of Market Participants are made with the understanding that market conditions may change for a range of reasons including technological improvements. Suboptimal

	operation of the transmission network is inequitable to Customers as they bear the burden of transmission congestion. **Workability.** The validation of EAP requests can be performed rapidly using existing processes and without major investment in additional capabilities or staffing resources. Based on experience in other regions, the number of EAP submissions would be limited (i.e., less than 2% of the number of transmission outage ticket submissions that ERCOT supports today). If EAPs were to become burdensome, the submission process could be streamlined to reduce workload or two additional ERCOT Staff may be warranted and justified given the significant benefits the process would provide to the ERCOT System. Further, EAP submissions would bear the burden of proving benefits, thus preventing spurious submissions. **Reliability.** ERCOT already leverages reconfigurations with CMPs for overload mitigation, showing their reliability value even during extreme system conditions. Adoption of EAPs will further improve reliability for issues not covered in current CMPs. **Planning.** Depending on the situation, topology reconfigurations can be deployed either as temporary solutions to congestion problems while transmission upgrades are pending or as longer-term solutions in areas where further transmission capacity need is not anticipated. This distinction makes it possible to account only for long-term topology reconfigurations that are approved as such by ERCOT and/or the Transmission Service Providers (TSPs) in the planning process.
PRS Decision	On 10/12/23, PRS voted unanimously to table NPRR1198 and refer the issue to ROS and WMS. All Market Segments participated in the vote. On 4/5/24, PRS voted to recommend approval of NPRR1198 as amended by the 3/8/24 LCRA comments. There were four abstentions from the Cooperative (STEC), Independent Generator (2) (Jupiter Power, Calpine), and Investor Owned Utility (IOU) (CNP) Market Segments. All Market Segments participated in the vote. On 5/9/24, PRS voted to endorse and forward to TAC the 4/5/24 PRS Report and 4/30/24 Impact Analysis for NPRR1198 with a recommended priority of 2025 and rank of 4520. There were three abstentions from the Cooperative (STEC), Independent Generator (Calpine), and IOU (CNP) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 10/12/23, participants discussed referring the issue to ROS and WMS, and requested leadership provide guidance on the scope of discussions at the subcommittees.

Board Report

	On 4/5/24, participants reviewed the 3/8/24 LCRA comments. On 5/9/24, participants reviewed the 4/30/24 Impact Analysis.
TAC Decision	On 5/22/24, TAC voted to recommend approval of NPRR1198 as recommended by PRS in the 5/9/24 PRS Report. There were four abstentions from the Cooperative (STEC), Independent Generator (2) (Jupiter Power, Calpine) and IOU (CNP) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, 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 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1198 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1198 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM supports approval of NPRR1198.
ERCOT Opinion	ERCOT supports approval of NPRR1198.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR 1198 and believes that it provides a positive market impact by leveraging ERCOT's existing CMP process to mitigate critical transmission congestion impacts.

Sponsor	
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Board Report

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Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
IMM 090623	Supported concept and encouraged approval of NPRR1198
Octopus Energy 092023	Supported NPRR1198
Engie 100423	Supported NPRR1198
EDF Renewables 103023	Integrated feedback received during stakeholder meeting discussions
WMS 110123	Requested PRS to continue to table NPRR1198 for further review by the Congestion Management Working Group (CMWG)
ROS 110323	Requested PRS to continue to table NPRR1198 for further review by the Operations Working Group (OWG)
Oncor 012224	Revised language to limit the scope of NPRR1198 to EAPs; modified the EAP definition to specify they are intended to address significant congestion; included the role of Outage Scheduling in the EAP management process
LCRA 030824	Modified the EAP definition to clarify it can be submitted for reliability and economic reasons
WMS 040424	Endorsed NPRR1198 as amended by the 3/8/24 LCRA comments
ROS 040424	Endorsed NPRR1198 as amended by the 3/8/24 LCRA comments

Market Rules Notes

None

Proposed Protocol Language Revision

2.1 DEFINITIONS

Constraint Management Plan (CMP)

A set of pre-defined manual transmission system actions, or automatic transmission system actions that do not constitute a Remedial Action Scheme (RAS), which are executed in response to system conditions to prevent or to resolve one or more thermal or non-thermal transmission security violations or to optimize the transmission system. ~~CMPs may be developed in cases where studies indicate economic dispatch alone may be unable to resolve a transmission security violation or in response to Real-Time conditions where Security-Constrained Economic Dispatch (SCED) is unable to resolve a transmission security violation.~~ ERCOT will employ CMPs to ~~facilitate the market use of the ERCOT Transmission Grid, while~~ maintain~~ing~~ system security and reliability in accordance with the Protocols, Nodal Operating Guides and North American Electric Reliability Corporation (NERC) Reliability Standards. ~~ERCOT may utilize Remedial Action Plans (RAPs) and Extended Action Plans (EAPs) to facilitate the market use of the ERCOT Transmission Grid for constraints that meet the criteria outlined in Nodal Operating Guide Section 11, Constraint Management Plans and Remedial Action Schemes. CMPs are intended to supplement, not to replace, the use of SCED for prevention or resolution of one or more thermal or non-thermal transmission security violations.~~

CMPs include, but are not limited to the following:

Automatic Mitigation Plan (AMP)

A set of pre-defined automatic actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating, excluding any set of automatic actions that constitute a Remedial Action Scheme (RAS). AMPs shall only include schemes which switch series reactors by monitoring quantities that are solely located at the same substation as the switched device. AMPs shall not include adjusting or tripping generation or Load shedding and shall not be implemented on Interconnection Reliability Operating Limits (IROLs).

Extended Action Plan (EAP)

A set of pre-defined manual actions to execute pre-contingency and to remain in place for a pre-defined period of time to address voltage issues or reduce overloading on one or more given monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. ~~An EAP may be utilized to address congestion on the ERCOT Transmission Grid that is resolvable by Security-Constrained Economic Dispatch (SCED), for constraints that have resulted in significant congestion costs~~ EAPs may be proposed by any Market Participant or developed by ERCOT and can be utilized for reliability or economic reasons. EAPs proposed for reliability reasons may have

thermal constraints that do not have a Security-Constrained Economic Dispatch (SCED) solution. EAPs proposed for economic reasons may have thermal constraints that are resolvable by SCED but result in high congestion costs and meet the criteria outlined in Nodal Operating Guide Section 11, Constraint Management Plans and Remedial Action Schemes. An EAP may include transmission switching and does not include Load shedding. EAPs shall be managed via the Network Operations Model Change Request (NOMCR) and Outage ~~S~~scheduling processes as described in Nodal Operating Guide Section 11.8.1, Extended Action Plan (EAP) Process.

Mitigation Plan

A set of pre-defined manual actions to execute post-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A Mitigation Plan must be implementable and may include transmission switching and Load shedding. Mitigation Plans shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

~~***Extended Action Plan (EAP)***~~

~~A set of pre-defined manual actions to execute pre-contingency and to remain in place for a pre-defined period of time to address voltage issues or reduce overloading on one or more given monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. An EAP may include transmission switching and does not include Load shedding. Implementation shall be managed via a change in normal status of breakers using the Network Operations Model Change Request (NOMCR) submission process.~~

Pre-Contingency Action Plan (PCAP)

A set of pre-defined manual actions to execute pre-contingency to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A PCAP may include transmission switching and does not include Load shedding. A PCAP may also be implemented for the duration of an Outage and shall be included in the Outage Scheduler as soon as practicable.

Remedial Action Plan (RAP)

A set of pre-defined manual actions to execute post-contingency to address voltage issues or in order to reduce loading on one or more given, monitored Transmission Facilities to below their Emergency Rating within 15 minutes. RAPs are sufficiently dependable to assume they can be executed without loss of reliability to the interconnected network, with restoration of normal operating conditions and below Normal Rating within two hours as defined in the Network Operations Model. RAPs may be relied upon in allowing additional use of the transmission system in Security-Constrained Economic Dispatch (SCED). RAPs shall not include generation re-Dispatch or Load shedding.

Temporary Outage Action Plan (TOAP)

A temporary set of pre-defined manual actions to execute post-contingency, during a specified Transmission Facility or Resource Outage, in order to address voltage issues or reduce overloading on one or more given, monitored Transmission Facilities to below their Emergency Rating with restoration of normal operating conditions within two hours. A TOAP must be implementable and may include transmission switching and/or Load shedding. TOAPs shall not be used to manage constraints in Security-Constrained Economic Dispatch (SCED).

3.10.7.4 Remedial Action Schemes, Automatic Mitigation Plans, Extended Action Plans and Remedial Action Plans

(1) All approved Remedial Action Schemes (RASs), Automatic Mitigation Plans (AMPs), Extended Action Plans (EAPs) and Remedial Action Plans (RAPs) must be defined in the Network Operations Model where practicable.

(2) Proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs and Resource Entities that own Transmission Facilities included in the RASs, ~~or~~ AMPs, EAPs or RAPs, and shall approve proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs, EAPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

[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) Proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs must be submitted to ERCOT for review and approval. ERCOT shall seek input from TSPs, DCTOs, and Resource Entities that own Transmission Facilities included in the RASs, ~~or~~ AMPs, EAPs or RAPs, and shall approve proposed new RASs, AMPs, EAPs and RAPs and proposed changes to RASs, AMPs, EAPs and RAPs in accordance with the process outlined in the Operating Guides. This shall include verification of the Network Operations Model. ERCOT shall provide notification to the market and post all RASs, AMPs, EAPs and RAPs under consideration on the MIS Secure Area within five Business Days of receipt.

(3) ERCOT shall use a NOMCR to model approved RASs, AMPs, EAPs and RAPs where practicable and include the RASs, AMPs, EAPs or RAPs modeled in the Network Operations Model in the security analysis. The NOMCR shall include a detailed description of the system conditions required to implement the RASs, AMPs, EAPs or RAPs. If an approved RAS, AMP, or RAP cannot be modeled, then ERCOT shall develop an alternative method for recognizing the unmodeled RAS, AMP, or RAP in its tools. Execution of RASs, AMPs, EAPs or RAPs modeled in the Network Operations Model shall be included or assumed in the calculation of LMPs. ERCOT shall provide notification to the market and post on the MIS Secure Area all approved RASs, AMPs, EAPs and RAPs at least two Business Days before implementation, identifying the date of implementation. The notification to the market shall state whether the approved RAP, AMP, EAP or RAS will be modeled in the Network Operations Model. For RAPs developed in Real-Time, ERCOT shall provide notification to the market as soon as practicable.

6.5.1.1 ERCOT Control Area Authority

(1) ERCOT, as Control Area Operator (CAO), is authorized to perform the following actions for the limited purpose of securely operating the ERCOT Transmission Grid under the standards specified in North American Electric Reliability Corporation (NERC) Standards, the Nodal Operating Guides and these Protocols, including:

(a) Direct the physical operation of the ERCOT Transmission Grid, including circuit breakers, switches, voltage control equipment, and Load-shedding equipment;

(b) Dispatch Resources that have committed to provide Ancillary Services;

[NPRR1010: Replace paragraph (b) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(b) Dispatch Resources that have been awarded Ancillary Services;

(c) Direct changes in the operation of voltage control equipment;

(d) Direct the implementation of Reliability Must-Run (RMR) Service~~;, Remedial Action Plans (RAPs), Automatic Mitigation Plans (AMPs), Remedial Action Schemes (RASs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and~~

(e) Direct the implementation, disabling, or reversal of implementation of Remedial Action Plans (RAPs), Automatic Mitigation Plans (AMPs), Remedial Action Schemes (RASs), Pre-Contingency Action Plans (PCAPs), Extended Action Plans (EAPs), and transmission switching to prevent the violation of ERCOT Transmission Grid security limits; and

(fe) Perform additional actions required to prevent an imminent Emergency Condition or to restore the ERCOT Transmission Grid to a secure state in the event of an ERCOT Transmission Grid Emergency Condition.

(2) Unless the ERCOT Protocols or Other Binding Documents explicitly provide otherwise, ERCOT shall not model, monitor, direct operation of, or otherwise exercise any operational authority over any facility that operates on the low voltage side of the distribution transformer except as may be necessary for the following purposes:

(a) To ensure the reliable interconnection, dispatch, operation, and Settlement of any Generation Resource, Energy Storage Resource (ESR), Load Resource, or Emergency Response Service (ERS) Resource that is, or is proposed to be, interconnected at distribution voltage, and to ensure the reliable operation and Settlement of any other ERCOT-registered generator or Energy Storage System (ESS);

(b) To provide ERCOT information about all generators and ESS interconnected at distribution voltage as requested by ERCOT pursuant to these Protocols or Other Binding Documents for the purposes of ensuring accurate Settlement and operating and planning the ERCOT Transmission Grid; and

(c) To effectuate automatic or manual Load-shedding as prescribed by these Protocols or Other Binding Documents.

(3) Nothing in paragraph (2) above limits ERCOT's authority to require that a Transmission Service Provider (TSP) or Transmission Operator (TO) disconnect any Facility operated at distribution voltage from the ERCOT System if ERCOT determines such action is necessary to address a reliability concern on the ERCOT Transmission Grid. Additionally, nothing in paragraph (2) above limits ERCOT's authority to require appropriate modeling and telemetry of transmission Loads that may represent multiple distribution-level Loads, as provided in Section 3.10.7.2, Modeling of Resources and Transmission Loads.

(4) Consistent with paragraph (1)(ef) above, if ERCOT seeks to exercise its authority to prevent an anticipated Emergency Condition relating to serving Load in the current or next Season by procuring existing capacity that may be used to maintain ERCOT System reliability in a manner not otherwise delineated in these Protocols and the Nodal Operating Guides, ERCOT shall take the following actions:

(a) Upon determination by ERCOT that additional capacity is needed to prevent an Emergency Condition and prior to any procurement activity associated with such additional capacity, ERCOT shall issue a Notice as soon as practicable with the following information:

(i) A detailed description of the reliability condition and need for additional capacity as determined by ERCOT and the timing of the proposed procurement;

(ii) Justification for the quantity of additional capacity to be requested;

(iii) Identification of potential Generation Resources or Load providing capacity considered by ERCOT to be acceptable for providing the additional capacity. Load capacity may be provided by Entities who, at ERCOT's direction, would interrupt consumption of electric power and remain interrupted until released by ERCOT; and

(iv) A schedule of activities associated with the proposed procurement.

(b) If ERCOT identifies a specific Entity with which it will negotiate the terms for procurement of additional capacity, then ERCOT shall issue a Notice as soon as practicable that includes the Entity name and, as applicable, the Resource mnemonic, the Resource MW rating by Season, the name of the Resource Entity, and the potential duration of any contract, including anticipated start and end dates.

(c) ERCOT shall, to the fullest extent practicable, ensure that any actions taken to procure additional capacity meet the following criteria:

(i) Any capacity procured pursuant to this paragraph will be procured using an open process, and the terms of the procurement between ERCOT and the Entity will be memorialized in contracts that will be publicly available for inspection on the ERCOT website.

(ii) Each contract will include specified financial terms and termination dates. For purposes of Settlement, any contract associated with a Generation Resource will include substantially the same terms and conditions as an RMR Unit under a RMR Agreement, including the Eligible Cost budgeting process.

(iii) ERCOT shall provide notice to the ERCOT Board, at the next ERCOT Board meeting after ERCOT has signed the contract, that the actions required prior to execution of the contract, pursuant to paragraphs (4)(a) through (c) above, were completed by ERCOT before the contract was executed.

(iv) Any information submitted by the Entity to ERCOT through the procurement process may be designated as Protected Information and treated in accordance with the provisions of Section 1.3, Confidentiality, provided that final contract terms must be made available for public inspection.

(d) A Generation Resource that has received capital contributions from ERCOT pursuant to a contract executed under this paragraph (4) may not participate in the energy or Ancillary Services markets until such capital contributions have been refunded to ERCOT. For the purposes of this Section, capital contributions are defined as improvements with an asset life greater than one year under the

applicable federal tax rules. The Resource Entity's refund of capital contributions shall be a lump sum payment calculated as follows:

(i) If the Generation Resource chooses to participate in the energy or Ancillary Service markets after the termination date of the contract executed under this paragraph (4), the Qualified Scheduling Entity (QSE) representing the Resource Entity shall repay, in a lump sum payment, 100% of the book value of the capitalized equipment and all installation charges leading to turn key, one-time startup based on a linear depreciation over the estimated life of the capitalized component(s) in accordance with Generally Accepted Accounting Principles (GAAP) standards for electric utility equipment. The estimated life shall be based on documentation provided by the manufacturer; if installing used equipment, the estimated life may be based on an approximation agreed to by the Resource Entity and ERCOT.

(ii) If the Generation Resource chooses to participate in the energy or Ancillary Services markets as contemplated in item (4)(d)(i) above, and its participation requires a lump sum payment of capital contributions, ERCOT will issue a notice to all registered Market Participants announcing the Generation Resource's decision to participate in the market(s) and identifying the amount of the lump sum payment due pursuant to item (4)(d)(i) above. ERCOT will also issue a notice to all registered Market Participants after completion of the collection and disbursement of the capital contributions, as described in item (4)(d)(iii) below, and after resolution of any disputes related to these capital contributions.

(iii) After ERCOT receives a Notification of Change of Generation Resource Designation (Section 22, Attachment H, Notification of Change of Generation Resource Designation) changing the Resource designation to "operational" at a future date, ERCOT shall charge the QSE representing the Resource Entity for capital expenditures incurred and previously paid to the Resource Entity as a result of the Resource's return to service pursuant to this Section.

(A) For months in the contract term where notice is received more than five Business Days prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any payments made for the capital expenditure associated with that month and subsequent months of the term, on the next practical Settlement but no later than the True-Up Settlement.

(B) For months in the contract term where notice is received five Business Days or less prior to True-Up Settlement of the first Operating Day of that month, ERCOT shall claw back any

payments made for the capital expenditures within 45 days of receipt of the notice.

(C) ERCOT shall distribute the repayment to QSEs representing Load on the same basis used to collect the monthly capital expenditures, using a monthly Load Ratio Share (LRS). A QSE's monthly LRS shall be the QSE's total Real-Time Adjusted Metered Load (AML) for the month divided by the total ERCOT Real-Time AML for the same month.

(e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the System-Wide Offer Cap (SWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion.

[NPRR1010: Replace paragraph (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(e) ERCOT shall endeavor to minimize the deployment of capacity procured pursuant to this paragraph with the goal of reducing the potential distortion of markets. Resources and Loads deployed to alleviate imminent Emergency Conditions will not be offered into the Day-Ahead Market (DAM). Rather, ERCOT will determine whether to use the capacity as part of the Hourly Reliability Unit Commitment (HRUC) process based on system conditions and the ability to meet Demand. In the event Generation Resources are committed and On-Line, ERCOT systems will generate a proxy offer for the Generation Resource at the Real-Time System-Wide Offer Cap (RTSWCAP). The default offer will place the Generation Resources among the last for economic Dispatch, so as not to displace Generation Resources that are On-Line and offering into the market. To the extent practicable, the capacity deployed to alleviate imminent Emergency Conditions will not be used solely for the purpose of reducing local congestion.

(f) An Entity cannot be compelled to enter into a contract under this paragraph.

ERCOT Impact Analysis Report

NPRR Number	1198	NPRR Title	Congestion Mitigation Using Topology Reconfigurations
Impact Analysis Date		April 30, 2024	
Estimated Cost/Budgetary Impact		Between $50k and $80k Annual Recurring Operations and Maintenance (O&M) Budget Cost: Between $180k and $220k See ERCOT Staffing Impacts	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 4 to 7 months	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor There will be ongoing operational impacts to the following ERCOT department totaling 1.0 Full-Time Employees (FTE) to support this NPRR: • Grid Analysis (1.0 FTE effort) ERCOT has assessed its ability to absorb the ongoing efforts of this NPRR with current staff and concluded the need for one additional FTE in Grid Analysis: *1440 hours to perform the multi-timepoint economic analysis on four EAPs using reasonable scenarios, facilitate and incorporate market comments, and coordinate EAPs activation or de-activation with internal and external parties from system changes to field switching. 440 hours to cover annual economic analysis methodology review, economic analysis tools maintenance, compliance support, and training.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Energy Management Systems 85% • ERCOT Website and MIS Systems 11% • Channel Management Systems 4%	
ERCOT Business Function Impacts		ERCOT will update its business processes to implement this NPRR.	

ERCOT Impact Analysis Report

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	1212	NPRR Title	Clarification of Distribution Service Provider's Obligation to Provide an ESI ID
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		The first of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		2.1, Definitions 10.3.2, ERCOT-Polled Settlement Meters 10.3.2.1, Generation Resource Meter Splitting 10.3.2.1.2, Allocating EPS Metered Data to Split Generation Resource Meters 10.3.2.1.3, Processing for Missing Dynamic Split Generation Resource Signal	
Related Documents Requiring Revision/Related Revision Requests		Planning Guide Revision Request (PGRR) 114, Related to NPRR1212, Clarification of Distribution Service Provider's Obligation to Provide an ESI ID	
Revision Description		This Nodal Protocol Revision Request (NPRR) revises Section 10.3.2 to clarify the obligation of a Distribution Service Provider (DSP) to provide ERCOT with an Electric Service Identifier (ESI ID) for a Resource site that consumes Load other than Wholesale Storage Load (WSL) and that is not behind a Non-Opt-In Entity (NOIE) tie meter.	
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	

Board Report

	☐ 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 improvements ☒ Regulatory requirements ☐ ERCOT Board and/or 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	Some Resources in the Resource integration process have begun consuming electricity without ERCOT receiving ESI ID(s). In the past, ERCOT has attributed that energy to Unaccounted for Energy (UFE) and has addressed this in the Final or True-Up Settlement at a later date. However, after 180 days, this cannot be remedied through the True-Up process. ERCOT needs to receive ESI ID(s) earlier in the Resource integration process to avoid the accrual of UFE that cannot be easily resettled. ERCOT has determined that clarification of the Protocols is needed to ensure that ERCOT timely receives ESI ID(s) before Initial Energization of a project at a Resource site. Additionally, the modifications in Sections 10.3.2.1, 10.3.2.1.2, and 10.3.2.1.3 are proposed because meters (Resource IDs (RIDs)) are not represented by QSEs and, for Settlement purposes, are not associated with Generation Resources.
PRS Decision	On 12/15/23, PRS voted unanimously to table NPRR1212. All Market Segments participated in the vote. On 3/20/24, PRS voted to recommend approval of NPRR1212 as amended by the 2/22/24 Oncor comments as revised by PRS. There were two abstentions from the Cooperative (STEC) and Investor Owned Utilities (Linebacker Power, LLC) Market Segments. All Market Segments participated in the vote. On 4/5/24, PRS voted to endorse and forward to TAC the 3/20/24 PRS Report and 11/22/23 Impact Analysis for NPRR1212. There were three abstentions from the Cooperative (STEC), Independent Generator (ENGIE), and Independent Power Marketer (IPM) (Tenaska) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 12/15/23, ERCOT Staff reviewed NPRR1212 and referenced PGRR114, tabled at the December 7, 2023 Reliability and

	Operations Subcommittee (ROS) meeting. Participants requested that PRS table NPRR1212 to provide time to clarify mechanics and for additional discussion at the Resource Integration Working Group (RIWG). On 3/20/24, PRS reviewed the 1/5/24 STEC, 2/22/24 Oncor, and 3/19/24 Aypa Power comments. Participants applied desktop edits to paragraph (2)(c) of Section 10.3.2 of the 2/22/24 Oncor comments, removing conditional DSP tariff and Standard Generation Interconnection Agreement (SGIA) language regarding DSPs providing ESI ID(s) to ERCOT and Resource Entities. On 4/5/24, PRS reviewed the 11/22/23 Impact Analysis.
TAC Decision	On 4/15/24, TAC voted to recommend approval of NPRR1212 as recommended by PRS in the 4/5/24 PRS Report. There were four abstentions from the Cooperative (GSEC, LCRA, PEC, STEC) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 4/15/24, TAC reviewed the 4/12/24 STEC and ERCOT comments. Some participants questioned if NPRR1212, as written, fully resolves the change that it proposes.
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 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1212 as recommended by TAC in the 4/15/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1212 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 NPRR1212.

Board Report

ERCOT Opinion	ERCOT supports approval of NPRR1212.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1212 and believes that it provides a positive market impact by offering regulatory requirements that clarify the obligation of a DSP to provide ERCOT with an ESI ID for a Resource site that consumes Load other than WSL and that is not behind a NOIE tie meter.

Sponsor	
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Company	ERCOT
Phone Number	512-248-3943 / 512-248-6582 / 512-275-7447 / 512-275-7436
Cell Number	
Market Segment	Not applicable

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

Comments Received	
Comment Author	**Comment Summary**
STEC 010524	Clarified that DSPs are required to provide ESI ID(s) to ERCOT and Resource Entities upon meeting the applicable requirements of the DSP's tariff and/or specified SGIA
Oncor 022224	Proposed various clarification and specification language; incorporated edits proposed in the 1/5/24 STEC comments
Aypa Power 031924	Requested PRS recommend approval of NPRR1212 as submitted; proposed, alternatively, edits to the 2/22/24 Oncor comments replacing conditional DSP tariff language with conditional PUCT order/rule language regarding DSPs providing ESI ID(s) to ERCOT and Resource Entities

Board Report

RMS 040324	Endorsed NPRR1212 as recommended by PRS in the 3/20/24 PRS Report
STEC 041224	Resubmitted edits to paragraph (2)(c) of Section 10.3.2 for consideration at the April 15, 2024 TAC meeting
ERCOT 041224	Urged TAC to oppose the 4/12/24 STEC comments

Market Rules Notes

Administrative changes to the language were made and authored as "ERCOT Market Rules."

Proposed Protocol Language Revision

2.1 DEFINITIONS

Resource ID (RID)

A unique identifier assigned to each ERCOT-Polled Settlement (EPS) Meter or Settlement Only Generator (SOG) meter. The RID for a SOG meter may be identical to the SOG's Electric Service Identifier (ESI ID)~~Resource used in the registration and Settlements systems managed by ERCOT~~.

10.3.2 ERCOT-Polled Settlement Meters

(1) Each TSP and DSP shall, in accordance with these Protocols and the Settlement Metering Operating Guide (SMOG), provide ERCOT-approved metering communication equipment and connection to permit ERCOT access to the TSP's or DSP's EPS Meters.

(2) For a Resource site that consumes Load other than Wholesale Storage Load (WSL) and is not behind a Non-Opt-In Entity (NOIE) tie meter:

(~~i~~a) A Resource site may not energize until ERCOT has received an Electric Service Identifier(s) (ESI ID(s)) to be used in the generation netting process for that site, and the ESI ID has been established in the ERCOT Settlement system in a state that allows for the Load to be properly settled to the appropriate Qualified Scheduling Entity (QSE);

(~~ii~~b) The Resource Entity must request an ESI ID(s) from the DSP(s) that will be serving the Load at the Resource site;

(~~iii~~c) Each DSP that will be serving Load at the Resource site shall provide ERCOT and the Resource Entity with the ESI ID(s) ~~if the requirements~~

~~and/or conditions of the DSP's tariff and/or the Standard Generation Interconnection Agreement (SGIA) have been met~~; and

(~~iv~~d) The Resource Entity must enter the ESI ID(s) in ERCOT's Resource Integration and Ongoing Operations (RIOO) interconnection services application, or alternate application designated by ERCOT.

~~, the DSP that has the right to serve Load at the Resource site shall provide ERCOT and the Resource Entity with Electric Service Identifier(s) (ESI ID(s)) to be used in the generation netting process.~~

(3~~2~~) ERCOT shall retrieve meter data electronically and automatically by MDAS. ERCOT may also collect meter data on demand.

10.3.2.1 Generation Resource Meter Splitting

(1) Each Generation Resource ~~meter~~ must be represented by only one ~~Qualified Scheduling Entity (~~QSE~~)~~, except that a jointly owned Generation Resource unit or group of Generation Resources may split the net generation output into two or more Split Generation Resources for a Resource Entity. Each Resource Entity representing a Split Generation Resource may have its energy and capacity scheduled through a separate QSE. For purposes of this paragraph, a jointly owned Generation Resource unit or group of Generation Resources shall also include the San Miguel and Gibbons Creek power projects and Intermittent Renewable Resources (IRRs) such as wind and solar generation.

(2) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the Resource Entities representing the Split Generation Resources shall be required to submit a percentage allocation of the Generation Resource to be used to determine the capacity available at each Split Generation Resource.

(3) When a Generation Resource that has been split to function as two or more Split Generation Resources is registered with ERCOT, the owners of the Generation Resource shall submit all required ERCOT Facility registration documentation and an ERCOT-approved splitting agreement executed by an Authorized Representative from each owning Resource Entity. Such agreement shall contain a defined and fixed ownership percentage as among the owning Resource Entities. ERCOT shall establish this Generation Resource as a "split," essentially establishing Split Generation Resource meters. Generation splitting based on a static ratio is not permitted. Generation splitting requires Real-Time splitting signals.

10.3.2.1.2 Allocating EPS Metered Data to Split Generation Resource Meters

(1) ERCOT shall poll the EPS Metering Facilities related to the actual Generation Resource and store the meter data at 15-minute intervals. This metering data must be validated, edited, estimated, and compensated for losses, as necessary, and be netted as required. This resulting data must then have the Split Generation Resource ratios applied to assign the generation to the QSE representing each owner of the Split Generation Resources.

The MWh quantities of the Split Generation Resources must be used in all Settlement calculations and reports.

(2) The following example illustrates the splitting of the generation data:

Splitting Example 1

Integrated values from ERCOT systems						Actual Metered MWh	Data to be Used in Settlement		
Interval Ending	~~UNIT~~R ~~ID~~1 (MWh)	~~UNIT~~R ~~ID~~2 (MWh)	~~UNIT~~R ~~ID~~3 (MWh)	Total MWh	% Ratios ~~Rid~~ Unit 1,2,3		Split MWh	Split MWh	Split MWh
13:15	10	20	10	40	25, 50, 25	52	13	26	13

10.3.2.1.3 Processing for Missing Dynamic Split Generation Resource Signal

(1) For any interval when ERCOT has not received a Real-Time signal for any one of the Split Generation Resources, ERCOT shall use the last valid percentage ratio for a completed interval.

Splitting Example 2

Integrated values from ERCOT systems						Actual Metered MWh	Data to be Used in Settlement		
Interval Ending	~~UNIT~~R ~~ID~~1 (MWh)	~~UNIT~~R ~~ID~~2 (MWh)	~~UNIT~~R ~~ID~~3 (MWh)	Total MWh	% Ratios ~~Rid~~ Unit 1,2,3		Split MWh	Split MWh	Split MWh
13:15	10	20	10	40	25, 50, 25	52	13	26	13
13:30	NA	21	10	NA	Ratio Above	55	13.75	27.5	13.75
13:45	NA	22	10	NA	Ratio Above	48	12	24	12

ERCOT Impact Analysis Report

NPRR Number	1212	NPRR Title	Clarification of Distribution Service Provider's Obligation to Provide an ESI ID
Impact Analysis Date		November 22, 2023	
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		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

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

Comments
None.

Board Report

NPRR Number	1218	NPRR Title	REC Program Changes Per P.U.C. Subst. R. 25.173, Renewable Energy Credit Program
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: Less than $20k (Operations & Maintenance (O&M)) Project Duration: No project required	
Proposed Effective Date		Upon system implementation	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		1.1, Summary of the ERCOT Protocols Document 1.3.1.1, Items Considered Protected Information 2.1, Definitions 2.2, Acronyms and Abbreviations 14.1, Overview 14.2, Duties of ERCOT 14.3.2, Attributes of Renewable Energy Credits and Compliance Premiums 14.5.2, Retail Entities 14.5.3, End-Use Customers 14.6.1, Adjustments to Renewable Energy Credit Award Calculations 14.6.2, Awarding of Compliance Premiums 14.8, Renewable Energy Credit Offsets 14.9, Allocation of Statewide Renewable Portfolio Standard Requirement Among Retail Entities 14.9.1, Annual Capacity Targets 14.9.2, Capacity Conversion Factor 14.9.3, Statewide Renewable Portfolio Standard Requirement 14.9.3.1, Preliminary Renewable Portfolio Standard Requirement for Retail Entities 14.9.4, Application of Offsets - Adjusted Renewable Portfolio Standard Requirement 14.9.5, Final Renewable Portfolio Standard Requirement 14.10.1, Mandatory Retirement 14.10.2, Voluntary Retirement	

Board Report

	14.13, Submit Annual Report to Public Utility Commission of Texas
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	This Nodal Protocol Revision Request (NPRR) updates Section 14, State of Texas Renewable Energy Credit Trading Program, to comply with P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program. This includes an update of the Renewable Portfolio Standard (RPS) requirement to pertain to only solar renewable energy.
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 improvements ☐ 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	Alignment between Protocols and Public Utility Commission of Texas (PUCT) Substantive Rules is necessary and proper.
PRS Decision	On 3/20/24, PRS voted unanimously to table NPRR1218. All Market Segments participated in the vote. On 4/5/24, PRS voted unanimously to recommend approval of NPRR1218 as amended by the 4/4/24 Reliant comments as revised by PRS. All Market Segments participated in the vote.

Board Report

	On 5/9/24, PRS voted unanimously to endorse and forward to TAC the 4/5/24 PRS Report and 3/5/24 Impact Analysis for NPRR1218. All Market Segments participated in the vote.
Summary of PRS Discussion	On 3/20/24, PRS reviewed NPRR1218 and the 3/15/24 TEBA comments. ERCOT Staff confirmed that Renewable Energy Credits (RECs) are still being tracked and rewarded; and expressed support for the 3/15/24 TEBA comments. One participant requested tabling NPRR1218 in anticipation of upcoming comments. On 4/5/24, PRS reviewed the 4/4/24 Reliant comments. ERCOT Staff requested NPRR1218 implementation by end of year and proposed a clarifying edit to paragraph (1) of Section 14.1 of the 4/4/24 Reliant comments. On 5/9/24, PRS reviewed the 3/5/24 Impact Analysis.
TAC Decision	On 5/22/24, TAC voted unanimously to recommend approval of NPRR1218 as recommended by PRS in the 5/9/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, 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 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1218 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1218 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.

Board Report

Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NPRR1218.
ERCOT Opinion	ERCOT supports approval of NPRR1218.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1218 and believes that it provides a positive market impact by updating Section 14 to comply with P.U.C. SUBST. R. 25.173.

Sponsor	
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Company	ERCOT
Phone Number	512-248-3944
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Jordan Troublefield
E-Mail Address	Jordan.Troublefield@ercot.com
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Comments Received	
Comment Author	**Comment Summary**
TEBA 031524	Endorsed NPRR1218 and requested that ERCOT support the filing of an NPRR in the next six months that implements ERCOT's rights under P.U.C. SUBST. R. 25.173 to track additional attributes in energy certificates
Reliant 040424	Provided clarifying edits to ensure that past data related to the opt-out of transmission-level Customers associated with the prior RPS program retains its Protected Information status among newly-proposed definitions, and to better align NPRR1218 with PUCT Substantive Rules

Board Report

Market Rules Notes

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

- NPRR1181, Submission of Coal and Lignite Inventory Notifications (incorporated 3/1/24)
  - Section 1.3.1.1

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

- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Section 1.3.1.1

Proposed Protocol Language Revision

1.1 Summary of the ERCOT Protocols Document

(1) The Electric Reliability Council of Texas (ERCOT) Protocols, created through the collaborative efforts of representatives of all segments of Market Participants, means the document adopted by ERCOT, including any attachments or exhibits referenced in these Protocols, as amended from time to time, that contains the scheduling, operating, planning, reliability, and Settlement (including Customer registration) policies, rules, guidelines, procedures, standards, and criteria of ERCOT. To determine responsibilities at a given time, the version of the ERCOT Protocols in effect at the time of the performance or non-performance of an action governs with respect to that action. These Protocols are intended to implement ERCOT's functions as the Independent Organization for the ERCOT Region as certified by the Public Utility Commission of Texas (PUCT) and as the Program Administrator appointed by the PUCT that is responsible for carrying out the administrative responsibilities related to the Renewable Energy Credit (REC) Program as set forth in subsection (~~g~~h) of P.U.C. SUBST. R. 25.173, ~~Goal for~~ Renewable Energy Credit Program. Market Participants, the Independent Market Monitor (IMM), and ERCOT shall abide by these Protocols.

(2) The ERCOT Board, Technical Advisory Committee (TAC), and other ERCOT subcommittees authorized by the ERCOT Board or TAC or ERCOT may develop polices, guidelines, procedures, forms, and applications for the implementation of and operation under, these Protocols and to comply with applicable rules, laws, and orders of a Governmental Authority. A policy, guideline, procedure, form, or application described above is an "Other Binding Document." Other Binding Documents do not include ERCOT's internal administrative procedures, documents and processes necessary to fulfill its role as the Independent Organization or as a registered Entity with the North American Electric Reliability Corporation (NERC).

(3) ERCOT shall post the Other Binding Documents List and all Other Binding Documents to a part of the ERCOT website reserved for posting Other Binding Documents. A TAC designated subcommittee shall review the Other Binding Documents List at least every four years, and modifications to the Other Binding Documents List shall be reviewed and considered by the TAC designated subcommittee and by TAC at its next scheduled meeting.

(4) Any revision of an Other Binding Document must follow the revision process set forth in that Other Binding Document. If an Other Binding Document does not specify a revision process, the Other Binding Document shall be subject to the procedures in Section 21, Revision Request Process, and shall be treated as if it were a Protocol for purposes of the revision process.

(5) To the extent that Other Binding Documents are not in conflict with these Protocols or with an Agreement to which it is a party, each Market Participant, the IMM, and ERCOT shall abide by the Other Binding Documents. Taken together, these Protocols and the Other Binding Documents constitute all of the "scheduling, operating, planning, reliability, and Settlement policies, rules, guidelines, and procedures established by the independent System Operator in ERCOT," as that phrase is used in subsection (j) of the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2007) (PURA), Essential Organizations, that bind Market Participants.

(6) Except as provided below, if the provisions in any attachment to these Protocols or in any of the Other Binding Documents conflict with the provisions of Section 1, Overview, through Section 21, and Section 24, Retail Point to Point Communications, through Section 27, Securitization Uplift Charges, then the provisions of Section 1 through Section 21, and Section 24 through Section 27 prevail to the extent of the inconsistency. If any provision of any Agreement conflicts with any provision of the Protocols, the Agreement prevails to the extent of the conflict. Any Agreement provision that deviates from the standard form for that Agreement in Section 22, Attachments, must expressly state that the Agreement provision deviates from the standard form in Section 22. Agreement provisions that deviate from the Protocols are effective only upon approval by the ERCOT Board on a showing of good cause.

(7) These Protocols are not intended to govern the direct relationships between or among Market Participants except as expressly provided in these Protocols. ERCOT is not responsible for any relationship between or among Market Participants to which ERCOT is not a party.

1.3.1.1 Items Considered Protected Information

Commented [JT1]: Please note NPRR1188 also proposes revisions to this section.

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

(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) A Resource's Energy Offer Curve prices and quantities 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 probability of return to service and expected lead time for returning to service submitted pursuant to Section 3.14.1.9, Generation 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~~wish~~ 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~~j) of P.U.C. SUBST. R. 25.173, ~~Goal for~~ 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.

2.1 DEFINITIONS

Compliance Premium

A payment awarded by the Program Administrator in conjunction with an SREC that is generated by a renewable energy source that ~~is not powered by wind and~~ meets the criteria of subsection (~~l~~e) of P.U.C. SUBST. R. 25.173, ~~Goal for~~ Renewable Energy Credit Program. For the purpose of the Solar Renewable Portfolio Standard (SRPS) requirements, one Compliance Premium is equal to one SREC.

Renewable Energy Credit (REC) Trading Program

The Renewable Energy Credit Trading program, as described in Section 14, State of Texas Renewable Energy Credit Trading Program, and P.U.C. SUBST. R. 25.173, ~~Goal for~~ Renewable Energy Credit Program.

Repowered Facility

An existing facility that has been modernized or upgraded to use renewable energy technology to produce electricity consistent with P.U.C. SUBST. R. 25.173, ~~Goal for~~ Renewable Energy Credit Program.

Solar Renewable Portfolio Standard (SRPS)

The amount of solar capacity required to meet the requirements of ~~Public Utility Regulatory Act (PURA), TEX. UTIL. CODE ANN. § 39.904 (Vernon 1998 & Supp. 2007) and~~ P.U.C. SUBST. R. 25.173(f~~h~~).

Solar Renewable Energy Credit (SREC)

A tradable instrument that represents all of the renewable attributes associated with one MWh of production from a certified solar renewable generator.

2.2 ACRONYMS AND ABBREVIATIONS

ARR	Adjusted SRPS Requirement
FSRR	Final SRPS Requirement
SRPS	Solar Renewable Portfolio Standard
SREC	Solar Renewable Energy Credit
SSRR	Statewide SRPS Requirement

14.1 Overview

(1) On May 9, 2000, the Public Utility Commission of Texas (PUCT) appointed ERCOT as Program Administrator of the Renewable Energy Credits (REC) Trading Program described in subsection (he) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~. On November 30, 2023, the PUCT reaffirmed ERCOT as Program Administrator of the REC Trading Program described in subsection (a)(2) of P.U.C. SUBST. R. 25.173. The PUCT also established a Solar Renewable Portfolio Standard (SRPS) pursuant to Section 53 of House Bill 1500, enacted by the 88th Texas Legislature, Regular Session, to be phased out by September 1, 2025. Public Utility Regulatory Act (PURA) § 39.9113, adopted by the 88th Texas Legislature and implemented by the PUCT in P.U.C. SUBST. R. 25.173, require that ERCOT administer a voluntary trading program on an ongoing basis.

(2) The purposes of the REC Trading Program are:

(a) To ensure that the ~~cumulative~~total amount of installed generating capacity from new solar renewable energy technologies in this state totals 1,310~~2,280~~ megawatts (MW) by January 1, ~~2007~~2024~~,~~ and ~~3,272~~655 MW by January 1, ~~2009~~2025~~, 4,264 MW by January 1, 2011, 5,256 MW by January 1, 2013, and 5,880 MW by January 1, 2015, with a target of at least 500 MW of the total installed renewable capacity after September 1, 2005, coming from a renewable energy technology other than a source using wind energy, and that the means exist for the state to achieve a target of 10,000 MW of installed renewable capacity by January 1, 2025~~;

(b) To provide for a REC Trading Program to facilitate voluntary trading under subsection (g) of P.U.C. SUBST. R. 25.173 and PURA § 39.9113, and by which the solar renewable energy requirements established by ~~the~~ subsection (f) of P.U.C. SUBST. R. 25.173 ~~Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.904(a) (Vernon 1998 & Supp. 2007) (PURA)~~ may be achieved in the most

efficient and economical manner; to encourage the development, construction, and operation of new renewable energy Resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial Resources; to protect and enhance the quality of the environment in Texas through increased use of renewable Resources; and

(c) To ensure that all Customers have access to providers of energy generated by renewable energy Resources pursuant to PURA § 39.101(b)(3).

(3) ERCOT shall administer the REC Trading Program, which became effective July 1, 2001. Entities participating in the REC Trading Program must register with and execute the appropriate agreements with ERCOT.

14.2 Duties of ERCOT

(1) As described in more detail in this Section, ERCOT shall:

(a) Register renewable energy generators;

~~(b) Register offset generators;~~

(b~~e~~) Register Retail Entities;

(c~~d~~) Register other Entities choosing to participate in the Renewable Energy Credit (REC) Trading Program;

(d~~e~~) Create and maintain REC trading accounts for REC Trading Program participants;

(e~~f~~) Determine the annual Solar Renewable Portfolio Standard (SRPS) requirement for each Retail Entity in Texas using the formulas set forth in this Section;

(f~~g~~) On a quarterly basis, award RECs or Compliance Premiums earned by REC generators based on verified MWh production data;

(g~~h~~) Verify that Retail Entities meet annual SREC compliance requirements;

(h~~i~~) Retire RECs or Compliance Premiums as directed by REC Trading Program participants;

(i~~j~~) Retire RECs or Compliance Premiums as they expire;

(j~~k~~) On a monthly basis, make public the aggregated total MWh competitive energy sales in Texas;

(kl) Make public a list of REC Account Holders with contact information (e-mail, address, and telephone number) so as to facilitate REC or Compliance Premium trading;

(lm) Maintain a list of offset generators and the Retail Entities to whom such a generator's offsets were awarded by the Public Utility Commission of Texas (PUCT);

(mn) Conduct a REC Trading Program Settlement process annually;

(no) File an annual report with the PUCT as specified in subsection (hg)(11) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~;

(op) Monitor the operational status of participating renewable energy generation facilities in Texas and record retirements;

(pq) Compute and apply a revised Capacity Conversion Factor (CCF) (as described in Section 14.9.2, Capacity Conversion Factor) ~~every two years~~;

(qr) Audit MWh production data from certified REC generating facilities;

(rs) Audit MWh production from renewable energy generation facilities producing offsets for Retail Entities on an annual basis;

(st) Post a list of Facility Identification Numbers, and the associated renewable energy generation facility name, location, type, and noncompetitive certification data on the ERCOT website; and

(tu) Receive, implement and protect the confidentiality of Electric Service Identifiers (ESI IDs), identity of Retail Electric Provider (REP), and consumption data associated with transmission-level Customers that choose to have their Load excluded from the SRPS calculation consistent with Section 14.5.3, End-Use Customers, and subsection (fj) of P.U.C. SUBST. R. 25.173.

14.3.2 Attributes of Renewable Energy Credits and Compliance Premiums

(1) A REC or Compliance Premium is a tradable instrument that represents all of the renewable attributes associated with one MWh of production from a certified renewable generator. A REC or Compliance Premium may trade separately from energy. RECs are distributed to REC generators on a quarterly basis by ERCOT. The number of RECs distributed to a certified generator is based on physically metered MWh production. RECs may be traded, transferred, and retired.

(2) Compliance Premiums are awarded by the Program Administrator in conjunction with an SREC that is generated by a renewable energy Resource that ~~is not powered by wind and~~

meets the criteria of subsection (e1) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~. For the purpose of the Solar Renewable Portfolio Standard (SRPS) requirements, one Compliance Premium is equal to one REC. Compliance Premiums will not be awarded after December 31, 2024.

(3) The components of a REC and Compliance Premium are defined in the table below.

REC Information	Field Length	Description
Year	4 Digits	Year REC was issued.
Quarter	1 Digit	Quarter REC was issued.
Type of Renewable Resource	20 Characters	Reference to type of renewable Resource: Solar, wind, biomass, tidal, geothermal, hydro, landfill gas, other.
Facility Identification Number	5 Digits	Number to be assigned by ERCOT.
REC Number	8 Digits	REC Number 1 through the number of MWh generated by the facility during the quarter.

(4) The Facility Identification Number assigned by ERCOT will be fixed for a facility's lifetime, and will therefore remain constant regardless of changes in facility name or ownership. Facilities must file changes of name, ownership, or other relevant certification information with ERCOT within 30 days of such changes.

(5) Generating facilities that lose their Public Utility Commission of Texas (PUCT) REC generator certification will not be awarded RECs by ERCOT subsequent to the date of the certification revocation, unless ERCOT is otherwise directed by the PUCT.

(6) A REC or Compliance Premium will have an issue date of the Compliance Period in which it is generated.

(7) RECs and Compliance Premiums have a useful life of three Compliance Periods. For example, a qualifying MWh of renewable energy generated on December 31, ~~2006~~2023 will be the basis for a REC having an issue date of ~~2006~~2023. The three Compliance Periods for which this REC may be used are ~~2006~~2023, ~~2007~~2024, and ~~2008~~2025. This REC will expire one Business Day after March 31, ~~2009~~2026. March 31 is the date by which a Retail Entity must submit its annual REC compliance retirement information to ERCOT.

14.5.2 Retail Entities

(1) To enable Retail Entities the ability to calculate their Solar Renewable Portfolio Standard (SRPS) requirements, all Retail Entities serving Load in the state of Texas shall provide Load data to ERCOT on a monthly basis, and no later than the 38th day after the last Operating Day of the month, in an electronic format prescribed by ERCOT. The reported MWh quantity shall be solely the energy consumed by Customers in Texas. Load data shall be provided in one of the following processes:

(a) Retail Entities serving Load located within ERCOT shall have this function performed for them by ERCOT for the Load served within ERCOT. The data supplied by ERCOT shall be Settlement Quality Meter Data extracted from the ERCOT Settlement system; or

(b) Entities participating in the REC Trading Program that serve Load outside the ERCOT Region must report Settlement quality MWh Load data for Load served outside the ERCOT Region to ERCOT in a format prescribed by ERCOT.

(i) Entities reporting under paragraph (b) shall not include any MWhs served to a location for which a Customer has submitted a notice letter pursuant to subsection (f~~i~~) of P.U.C. SUBST. R 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~.

(ii) Notwithstanding the foregoing reporting requirements, such Entities shall submit monthly MWh Load data for December of each year by no later than January 15 of the following year. Any error in estimating December Load shall be corrected by the submitting Entity in the following year's true-up calculation as per subsection (f~~h~~)(2~~3~~) of P.U.C. SUBST. R. 25.173.

(2) On a monthly basis, ERCOT shall calculate the MWh consumption of energy by Customers served by Retail Entities in Texas, using Load data submitted by program participants. ERCOT shall adjust the Load data to ensure that any Load (MWh) covered by notice consistent with Section 14.5.3, End-Use Customers, is removed.

(3) The failure of a Retail Entity to report required Load data (including Load data for Electric Service Identifiers (ESI IDs) or accounts covered by notice, as specified in Section 14.5.3) in accordance with the Protocols shall result in estimation of Load data for the applicable Retail Entity by ERCOT for purposes of allocation of annual SRPS requirements.

14.5.3 End-Use Customers

(1) To enable ERCOT to determine the total retail sales of all Retail Entities and the retail sales of a specific Retail Entity for Section 14.9.3.1, Preliminary Solar Renewable Portfolio Standard Requirement for Retail Entities, and Section 14.9.5, Final Solar Renewable Portfolio Standard Requirement, a transmission-level voltage Customer that wishes to have its Load excluded from SRPS calculations pursuant to subsection (f~~i~~) of

P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~, must submit the information in accordance with the rule.

14.6.1 Adjustments to Renewable Energy Credit Award Calculations

(1) Adjustments (reductions) to REC awards are made for renewable facilities that use more than 2% fossil fuel, ~~renewable facilities that are repowered,~~ and for REC aggregators that use estimation techniques to report generation.

(a) Co-Fired Generator Adjustments:

(i) For REC generators using a renewable energy technology that requires the use of fossil fuel that is greater than 2%, and less than or equal to 25%, of the total annual fuel input on a British Thermal Unit (BTU) or equivalent basis, RECs can only be earned on the renewable portion of the production. RECs are awarded based on an adjusted number of MWh generated during the quarter.

(ii) The renewable energy Resource shall calculate the electricity generated by the unit in MWh, based on the BTUs (or equivalent) produced by the fossil fuel and the efficiency of the renewable energy Resource, subtract the MWh generated with fossil fuel input from the total MWh of generation and report the renewable energy generated to the Program Administrator;

~~(b) Repowered Facility Adjustments:~~

~~(i) A Repowered Facility is eligible to earn RECs on all renewable energy produced up to a capacity of 150 MW. Capacity greater than 150 MW may earn RECs for the energy produced in proportion to 150 divided by nameplate capacity.~~

~~(ii) Repowered Facilities with a generation capacity greater than 150 MW will be awarded RECs based on an adjusted number of MWh generated during the quarter.~~

~~$$AdjustedMWh = HO_q (150 / NC)$$~~

~~The above variables are defined as follows:~~

~~Variable~~	~~Unit~~	~~Description~~
~~HO_q~~	~~MWh~~	~~Total production or historical output by the Repowered Facility for quarter "q"~~
~~NC~~	~~None~~	~~Nameplate capacity is the machine generation capacity posted on a specific piece of equipment or unit~~

(be) REC Aggregator Adjustments:

The REC aggregator may provide the Program Administrator with sufficient information for the Program Administrator to estimate with reasonable accuracy the output of each unit, based on known or observed information that correlates closely with the generation output. REC aggregators using approved estimation techniques to report renewable energy production shall be awarded one REC for every 1.25 MWh generated.

14.6.2 Awarding of Compliance Premiums

(1) A Compliance Premium is awarded by the Program Administrator in conjunction with a REC that is generated by a renewable energy Resource installed and certified after September 1, 2005 that is not powered by wind. For the purpose of the Solar Renewable Portfolio Standard (SRPS) requirements, one Compliance Premium is equal to one REC.

(2) One Compliance Premium shall be awarded for each REC awarded for energy generated untilafter December 31, 20072024.

14.8 Renewable Energy Credit Offsets

(1) To qualify for Renewable Energy Credit (REC) offsets in the REC Trading Program, a Retail Electric Provider (REP), Municipally Owned Utility (MOU), generation and transmission cooperative, distribution cooperative, or an affiliate of a REP, MOU, generation and transmission cooperative, or distribution cooperative must apply for REC offsets from the Public Utility Commission of Texas (PUCT) by June 1, 2001. This requirement is in effect without regard to whether or not the applicant will be a Retail Entity on January 1, 2002. A REC offset represents one MWh of renewable energy from a renewable energy generator placed in service before September 1, 1999 that may be used in place of a REC to meet a renewable energy requirement. REC offsets may not be traded.

(2) After receipt of Notification from the PUCT (which shall include the name of the Entity receiving the offset, the name of the generator eligible to produce the offset, the value of the offset in MWh, and other information as applicable) verifying designation by the Entity receiving REC offsets, ERCOT shall use REC offsets from a Retail Entity as part of its calculation of Final Solar Renewable Portfolio Standard (SRPS) Requirements (FSRRs). REC offsets are not transferable. REC offsets will be considered valid until ERCOT receives Notification from the PUCT that the offset is no longer valid.

(3) For purposes of P.U.C. SUBST. R. 25.173, Renewable Energy Credit ProgramGoal for Renewable Energy, a generation and transmission cooperative shall be responsible for the cumulative total of its cooperative members' renewable energy requirements as well as

its affiliated cooperative members' renewable energy requirements. At the election of its board of directors, a generation and transmission cooperative will become responsible for the cumulative total of its distribution cooperatives' ~~Renewable Portfolio Standard (~~SRPS~~)~~ requirements. The sharing of the REC offsets of the generation and transmission cooperative among its distribution cooperatives shall not affect the cumulative total of the SRPS requirements of the distribution cooperative members, or its affiliated cooperative members in meeting their share of the state's goals for renewable energy Resources.

14.9 Allocation of Statewide Solar Renewable Portfolio Standard Requirement Among Retail Entities

(1) The first quarter of each year shall be the Settlement period for the preceding Compliance Period. During this Settlement period each year the following actions shall occur:

(a) No later than the date set forth in P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~, the Program Administrator shall allocate the Statewide Solar Renewable Portfolio Standard (SRPS) Requirement (SSRR) for the previous year's Compliance Period among all Retail Entities in the state. This allocation represents the Solar Renewable Energy Credit (SREC) compliance requirements for the preceding Compliance Period. To perform this calculation, ERCOT shall use Load data provided to it as set forth in these Protocols.

(b) By the date set forth in P.U.C. SUBST. R. 25.173, the Program Administrator shall notify each Retail Entity of its Final SRPS Requirement (FSRR) for the previous Compliance Period.

(c) The Program Administrator may request from the Public Utility Commission of Texas (PUCT) an adjustment to the deadlines set forth in this Section if certain factors, including but not limited to changes to the ERCOT Settlement Calendar, should affect the timely availability of reliable retail sales data or renewable Resource generation data necessary for calculating ~~Renewable Portfolio Standard (~~SRPS~~)~~ requirements.

14.9.1 Annual Capacity Targets

(1) The solar renewable energy capacity targets (in megawatts) for each year are as follows:

Annual Capacity Target (MW)	~~Existing Renewable Capacity (MW)~~	~~Total Renewable Capacity Target (MW)~~	Compliance Period (Years)
1,310~~400~~	~~880~~	~~1280~~	~~2002, 2003~~2024
~~850~~655	~~880~~	~~1730~~	2025~~2004, 2005~~

~~1400~~	~~880~~	~~2280~~	~~2006, 2007~~
~~2392~~	~~880~~	~~3272~~	~~2008, 2009~~
~~3384~~	~~880~~	~~4264~~	~~2010, 2011~~
~~4376~~	~~880~~	~~5256~~	~~2012, 2013~~
~~5000~~	~~880~~	~~5880~~	~~2014, and each year after 2014~~

~~(2) ERCOT shall increase the new renewable energy capacity target for all future Compliance Periods to account for:~~

~~(a) Capacity producing RECs from eligible qualifying out-of-state facilities metered in Texas; and~~

~~(b) Capacity from a renewable energy generator placed in service before September 1, 1999 that has been retired or otherwise removed from the program and results in a statewide existing renewable capacity of less than 880 MW.~~

~~ERCOT shall apply any such changes for out-of-state capacity and retirements at such time the revised Capacity Conversion Factor (CCF) is computed and applied.~~

(~~3~~2) RECs may be produced by generators certified by the PUCT which are not located in Texas if:

(a) The first metering point for such generation is in Texas; and

(b) All generation metered at the location of injection into the Texas grid comes from that generator.

(~~4~~3) REC generators physically located outside the state of Texas are not included in the annual calculations of installed renewable capacity for purposes of the REC Trading Program. However, as such generation may contribute to the available pool of RECs, it is conceivable that there may be sufficient RECs to allow Retail Entities to meet their annual requirements, while at the same time, a target capacity shortfall for installed renewable capacity in Texas could exist.

14.9.2 Capacity Conversion Factor

(1) ERCOT shall set the Capacity Conversion Factor (CCF) to allocate credits to Retail Entities. ~~The CCF shall be calculated during the fourth quarter of each odd-numbered compliance year.~~ ERCOT shall determine a new CCF as follows:

$$\textbf{Individual Facility CCF}_{i} = (12/n) * \sum_{t=1}^{n} \textbf{HO}_{\sout{il}, t} / (\textbf{HC}_{i,t} * \textbf{h}\sout{\textbf{8760}})$$

The above variables are defined as follows:

Variable	Unit	Description
h	None	Number of hours in the Compliance Period. h = 8,760 for the 2024 Compliance Period and 5,840 for the 2025 Compliance Period.
i	None	Individual solar renewable energy generation facility
n	None	Number of months a specific solar renewable energy generation facility was in operation over the past 24 months. *n* must be greater than or equal to 12 and less than or equal to 24.
$HO_{i,t}$	MWh	Total production by participating solar renewable generator *i* during Compliance Period *t*.
$HC_{i,t}$	MW	Average total generation capacity by participating solar renewable generator *i* during Compliance Period *t*.

and

$$\mathbf{CCF} = \sum_{i-1}^{q} (\mathbf{CCF}_i * \mathbf{PC}_i) / \sum_{i-1}^{q} \mathbf{PC}_i$$

The above variables are defined as follows:

Variable	Unit	Description
q	None	The total number of solar renewable energy generation facilities in the REC Trading Program
PC_i	MW	Participating Capacity as of September 30 of the year the revised CCF is calculated for solar renewable energy generation facility *i* in the state of Texas participating in the REC Trading Program for which at least 12 months of operating data are available.

(2) The CCF shall:

(a) Be based on actual solar generator performance data for calendar years 2022 and 2023~~the previous two years for~~ all solar renewable Resources in the REC Trading Program during that period for which at least 12 months of performance data are available;

(b) Represent a weighted average of generator performance; and

(c) Use all actual generator performance data that are available for each solar renewable Resource, excluding data for testing periods.

(3) For purposes of calculating historical output from renewable capacity, ERCOT shall keep a list of renewable generators, REC certification dates, and annual MWh generation totals.

(4) ERCOT shall use this revised CCF for the two Compliance Periods immediately after it is set (calendar years 2024 and 2025). If the PUCT has determined that the REC Trading

Program is failing to meet the statutory targets for solar renewable energy capacity in Texas, it will instruct ERCOT to use a different number than that which would be calculated using the formula for the CCF. Such requests will be published on the ERCOT website within ten Business Days of receipt of the letter from the PUCT.

14.9.3 Statewide Solar Renewable Portfolio Standard Requirement

(1) ERCOT shall determine the SSRR for a particular Compliance Period as follows:

SSRR = (ACT * h~~8760~~ * CCF) + RCP

The above variables are defined as follows:

Variable	Unit	Description
ACT	MW	Annual Capacity Target for new solar renewable energy generation facilities.
h~~8760~~	None	Number of hours in the Compliance Period. h = 8,760 for the 2024 Compliance Period and 5,840 for the 2025 Compliance Period.~~The number of hours in a year.~~
CCF	None	Capacity Conversion Factor.
RCP	None	The number of Compliance Premiums retired from solar Resources only during the previous Compliance Period.

14.9.3.1 Preliminary Solar Renewable Portfolio Standard Requirement for Retail Entities

(1) ERCOT shall determine each Retail Entity's Preliminary SRPS Requirement as follows:

Preliminary SRPS Requirement $_i$ = SSRR * (CRSRES $_i$ / TS)

The above variables are defined as follows:

Variable	Unit	Description
i	None	Specific Retail Entity.
SSRR	REC	Statewide SRPS ~~requirement~~Requirement.
CRSRES $_i$	MWh	Retail sales of the specific Retail Entity to Texas Customers during the Compliance Period, excluding sales by the specific Retail Entity to any Electric Service Identifiers (ESI IDs) or accounts for which an opt-out notice has been submitted under subsection (~~f~~j) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~.
TS	MWh	Total retail sales of all Retail Entities to Texas Customers during the Compliance Period, excluding all sales of all Retail Entities to ESI IDs or accounts for which an opt-out notice has been submitted under subsection (~~f~~j) of P.U.C. SUBST. R. 25.173.

(2) The sum of the Preliminary SRPS Requirements for all Retail Entities shall be equal to the SSRR.

14.9.4 Application of Offsets - Adjusted Solar Renewable Portfolio Standard Requirement

(1) For a Retail Entity that has been awarded offsets by the PUCT, ERCOT shall subtract the REC offset amount from the Preliminary SRPS Requirement. The reduction shall not exceed what would be necessary for the ~~Final RPS Requirement~~FSRR to be zero. The total MWh reduction in the Preliminary SRPS Requirement for all Retail Entities constitutes Total Useable Offsets (TUOs).

(2) ERCOT shall determine each Retail Entity's Adjusted SRPS Requirement (ARR) as follows:

$$\mathbf{ARR}_i = \mathbf{Preliminary\ SRPS\ Requirement}_i - \mathbf{EO}_i$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Specific Retail Entity.
EO_i	None	Total offsets the Retail Entity is entitled to receive during the Compliance Period (not to exceed the Retail Entity's FSRR before adjustment for any previous Compliance Period).

(3) ERCOT shall determine TUOs as follows:

$$\mathbf{TUO} = \mathbf{SSRR} - \sum_{i=1}^{n} \mathbf{ARR}_i$$

The above variables are defined as follows:

Variable	Unit	Description
i	None	Specific Retail Entity.
n	None	Number of Retail Entities.
SSRR	None	Statewide SRPS Requirement.
ARR_i	None	Adjusted SRPS Requirement for a specific Retail Entity.

14.9.5 Final Solar Renewable Portfolio Standard Requirement

(1) ERCOT shall redistribute the TUO amount over all Retail Entities to determine the FSRRs. ERCOT shall determine each Retail Entity's FSRR as follows:

$$\mathbf{FSRR} = \mathbf{ARR}_i + (\mathbf{TUO} \times (\mathbf{CRSRES}_i / \mathbf{TS})) +/- \mathbf{Previous\ Year(s)\ FSRR\ adjustment\ (recalculated\ in\ accordance\ with\ subsection\ (fh)(23)\ of\ P.U.C.\ SUBST.\ R.\ 25.173,\ Renewable\ Energy\ Credit\ Program\ ~~Goal\ for\ Renewable\ Energy~~)}$$

The above variables are defined as follows:

Variable	Unit	Description
ARR_i	None	Adjusted SRPS Requirement for a specific Retail Entity.
TUO	None	Total Usable Offsets.
$CRSRES_i$	MWh	Retail sales of the Retail Entity to Texas Customers during the Compliance Period, excluding sales by the specific Retail Entity to any ESI IDs or accounts for which an opt-out notice has been submitted under subsection (~~i~~f) of P.U.C. SUBST. R. 25.173.
TS	MWh	Total retail sales of all Retail Entities to Texas Customers during the Compliance Period, excluding all sales or accounts of all Retail Entities to ESI IDs for which an opt-out notice has been submitted under subsection (~~f~~) of P.U.C. SUBST. R. 25.173.

(2) This process will be an iterative process that will solve until the optimal allocation is reached with all FSRRs resolved to the nearest whole REC.

(3) ERCOT shall notify each Retail Entity of its FSRR for the previous Compliance Period no later than the date set forth for such Notification in subsection (~~i~~n)(1) of P.U.C. SUBST. R. 25.173.

14.10.1 Mandatory Retirement

(1) For each Compliance Period, by the date set forth in subsection (~~n~~i)(2) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~, each Retail Entity's Designated Representative shall notify ERCOT of the RECs or Compliance Premiums in its REC trading account to be used (retired) to satisfy its Final Solar Renewable Portfolio Standard (SRPS) Requirement (FSRR) for the Compliance Period being settled. Each REC or Compliance Premium that is not used will remain in the holder's REC trading account until it is transferred to another party's account, expires, or is otherwise retired.

(2) Failure to provide sufficient RECs or Compliance Premiums by the date set forth in subsection (~~i~~n)(2) of P.U.C. SUBST. R. 25.173 shall be considered a failure of that Retail Entity to meet its REC retirement obligations. ERCOT shall notify the Public Utility Commission of Texas (PUCT) when any Retail Entity fails to meet~~s~~ its REC retirement obligations.

14.10.2 Voluntary Retirement

(1) At the request of a REC Account Holder, ERCOT shall retire RECs and Compliance Premiums for reasons other than for meeting the mandated ~~Renewable Portfolio Standard (~~SRPS~~)~~ requirements. Voluntarily retired RECs and Compliance Premiums may not be used to satisfy a Retail Entity's SRPS requirement. ERCOT shall include information concerning RECs and Compliance Premiums retired voluntarily in its annual report to the PUCT.

Board Report

14.13 Submit Annual Report to Public Utility Commission of Texas

(1) Beginning in 2002, ERCOT shall submit an annual report to the Public Utility Commission of Texas (PUCT) on or before the date set forth for such report in subsection (~~h~~g)(11) of P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program~~Goal for Renewable Energy~~. Such report shall contain the following information pertaining to program operation for the previous Compliance Period:

(a) MW of existing renewable capacity installed in Texas, by technology type;

(b) MW of new renewable energy capacity installed in Texas, by technology type;

(c) List of eligible non-Texas capacity participating in the program, by technology type;

(d) Summary of Renewable Energy Credit (REC) aggregator activities, submitted in a format specified by the PUCT;

(e) Owner/operator of each REC generating facility;

(f) Date each new renewable energy facility began to produce energy;

(g) MWh of energy generated by renewable energy Resources as demonstrated through data supplied in accordance with these Protocols;

(h) List of renewable energy unit retirements;

(i) List of all Retail Entities participating in the REC Trading Program;

(j) Final Solar Renewable Portfolio Standard (SRPS) Requirement (FSRR) of each Retail Entity;

(k) Number of REC offsets used by each Retail Entity;

(l) A list of REC offset generators, REC offsets awarded and MWh production from each such generator on an annual basis;

(m) Number of RECs retired by each program participant by category (mandatory compliance, voluntary retirement, expiration, and total retirements);

(n) Number of Compliance Premiums retired by each program participant by category (mandatory compliance, expiration, and total retirements);

(o) List of all Retail Entities in compliance with ~~Renewable Portfolio Standard (~~SRPS~~)~~ requirement; and

(p) List of all Retail Entities not in compliance with SRPS requirement including the number of RECs by which they were deficient.

ERCOT Impact Analysis Report

NPRR Number	1218	NPRR Title	REC Program Changes Per P.U.C. SUBST. R. 25.173, Renewable Energy Credit Program
Impact Analysis Date		March 5, 2024	
Estimated Cost/Budgetary Impact		Less than $20k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.	
Estimated Time Requirements		No project required. This Nodal Protocol Revision Request (NPRR) can take effect within 2-3 months following Public Utility Commission of Texas (PUCT) approval.	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Renewable Energy Credit (REC) 100%	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

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

Comments
None.

Board Report

NPRR Number	1220	NPRR Title	Market Restart Approval Process Modifications
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		The first of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		25.3, Market Restart Processes	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Protocol Revision Request (NPRR) modifies the Market Restart process. The proposed process requires Technical Advisory Committee (TAC) and ERCOT Board approval, with an alternative mechanism to ERCOT Board approval where circumstances require it.	
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)	

Board Report

	☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	The current Protocol language is based on the pre-Senate Bill 2 ERCOT Board structure that included Market Segment representation, which is no longer in place. ERCOT Board approval, alone, no longer signals the market's readiness for a Market Restart. A new mechanism is needed to ensure market readiness prior to a Market Restart. This benefits the market by ensuring Market Participants, in addition to the ERCOT Board, are involved in making the decision on readiness for Market Restart.
PRS Decision	On 4/5/24, PRS voted unanimously to recommend approval of NPRR1220 as submitted. All Market Segments participated in the vote. On 5/9/24, PRS voted unanimously to endorse and forward to TAC the 4/5/24 PRS Report and 3/20/24 Impact Analysis for NPRR1220. All Market Segments participated in the vote.
Summary of PRS Discussion	On 4/5/24, PRS reviewed NPRR1220. On 5/9/24, PRS reviewed the 3/20/24 Impact Analysis.
TAC Decision	On 5/22/24, TAC voted unanimously to recommend approval of NPRR1220 as recommended by PRS in the 5/9/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)

Board Report

ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1220 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1220 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NPRR1220.
ERCOT Opinion	ERCOT supports approval of NPRR1220.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1220 and believes that it provides a positive market impact by modifying the Market Restart process to require TAC and ERCOT Board approval where circumstances require it.

Sponsor	
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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Protocol Language Revision

25.3 Market Restart Processes

(1) Specific Market Restart processes may be modified depending on the nature of the triggering event.

(2) Market Restart processes work in conjunction with, but will not supersede, other ERCOT emergency processes and procedures such as Black Start procedures.

(3) Following a declaration by ERCOT of a Market Suspension, in effectuating Market Restart for the Real-Time Market (RTM), ERCOT:

(a) Shall determine the interval to resume Security-Constrained Economic Dispatch (SCED) execution based on availability and functioning of:

(i) The Energy Management System (EMS);

(ii) The Market Management System (MMS);

(iii) The ERCOT System operating as a single Island as described in the Nodal Operating Guides; and

(iv) Electronic communications between ERCOT and Market Participants.

(b) Shall suspend all RTM Settlements and shall settle pursuant to Section 25.5, Market Suspension and Market Restart Settlement;

(c) Shall suspend Day-Ahead Market (DAM) Settlements for any Operating Days for which ERCOT declares the RTM was suspended;

(d) May assign Ancillary Services once the ERCOT System is operating as a single Island as described in the Nodal Operating Guides, and ERCOT is ready to control the system using Load Frequency Control (LFC); and

(e) Shall not restart the RTM until ERCOT has satisfied paragraph (6) below.

(4) When there are no posted DAM results for the Operating Day, and operational conditions allow, ERCOT shall assign Ancillary Services to Qualified Scheduling Entities (QSEs) based on the amount of capacity that their Resources have or can bring On-Line.

[NPRR1013: Replace paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(4) When there are no posted DAM results for the Operating Day, and operational conditions allow, ERCOT shall assign Ancillary Services to Qualified Scheduling Entities (QSEs) based on the amount of capacity that their Resources have or can bring On-Line. This process will remain in place until the RTM is able to award Ancillary Services to Resources.

(5) Following a declaration by ERCOT of a Market Suspension, in effectuating a Market Restart for the DAM, ERCOT shall restart the DAM when the below conditions are satisfied:

(a) The RTM has restarted pursuant to paragraph (3) above;

(b) ERCOT is reasonably able to model the expected state of the ERCOT Transmission Grid for the next day;

(c) ERCOT is able to receive market submissions to successfully run the DAM; and

(d) ERCOT has satisfied paragraph (6) below and has issued a Market Notice stating that it has obtained the necessary approvals.

(6) ERCOT shall not restart the RTM or DAM until:

(a) The Technical Advisory Committee (TAC) has approved the restart; and

(b) Either:

(i) The ERCOT Board has approved the restart ~~and ERCOT has issued a Market Notice stating that the ERCOT Board has approved the restart~~; or

(~~b~~ii) If, after taking into consideration the possibility of conducting an urgent meeting and holding such meeting by teleconference as set forth in paragraphs (b) and (c) of Section 4.6, Meetings, of the ERCOT Bylaws, it is not reasonably practicable to obtain ERCOT Board approval prior to the restart, the ERCOT CEO, or if designated by the ERCOT CEO, the ERCOT General Counsel, have approved the restart~~.~~, provided that

~~(i) The~~ the ERCOT CEO or ERCOT General Counsel shall not approve a restart of the RTM or DAM pursuant to this paragraph (~~b~~ii) unless the ~~ERCOT CEO or ERCOT General Counsel has consulted with each Market Segment Director or Segment Alternate to the extent a Market Segment Director is unavailable (as such terms are defined in the ERCOT Bylaws) and a majority of the Market Segment Directors and Segment Alternates consulted~~following parties have agreed in writing to restart the RTM or DAM as proposed by ERCOT~~.~~:

~~(ii) Prior to restarting the RTM or DAM pursuant to this paragraph (b), ERCOT shall issue a Market Notice stating that it was not reasonably practicable to obtain ERCOT Board approval prior to the restart, however, the majority of the Market Segment Directors and Segment Alternates have agreed in writing to restart the RTM or DAM.~~

(A) The ERCOT Board Chair, or the ERCOT Board Vice Chair in the case the ERCOT Board Chair is, either, unavailable or the position is vacant; and

(B) Either the Reliability and Markets Committee Chair or the Technology and Security Committee Chair.

(7) During the Market Restart process, credit constraints may be relaxed as applicable as detailed in Section 25.4, Market Suspension Credit Processes.

ERCOT Impact Analysis Report

NPRR Number	1220	NPRR Title	Market Restart Approval Process Modifications
Impact Analysis Date		March 20, 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	1222	NPRR Title	Public Utility Commission of Texas Approval of the Methodology for Determining Ancillary Service Requirements
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		The first of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		3.16, Standards for Determining Ancillary Service Quantities	
Related Documents Requiring Revision/Related Revision Requests		ERCOT Methodologies for Determining Minimum Ancillary Service Requirements	
Revision Description		This Nodal Protocol Revision Request (NPRR), consistent with ERCOT discussions with the PUCT, elevates final approval of the Other Binding Document titled, "ERCOT Methodologies for Determining Minimum Ancillary Service Requirements", from the ERCOT Board of Directors to the PUCT.	
Reason for Revision		☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive	

Board Report

	(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)
Justification of Reason for Revision and Market Impacts	Procurement of the suite of Ancillary Services has wide-ranging and significant impacts to operation of the ERCOT grid and ERCOT wholesale-market outcomes. In recognition of this significance, ERCOT, through discussion with the PUCT, proposes to include the PUCT as the final decision maker regarding changes to the Ancillary Service methodology. This NPRR is consistent with those PUCT discussions. ERCOT notes this NPRR only covers the PUCT approval of the Ancillary Service methodology. ERCOT intentionally limited the changes proposed in this NPRR in the hope it will go through the stakeholder process and be approved in time to be effective for PUCT approval of any changes to the 2025 Ancillary Service methodology. Future Revision Requests will be submitted for any other substantive changes to the Ancillary Service methodology that may result from ongoing stakeholder discussions or pending PUCT Project No. 55845, *Review of Ancillary Services in the ERCOT Market*.
PRS Decision	On 4/5/24, PRS voted unanimously to recommend approval of NPRR1222 as submitted. All Market Segments participated in the vote. On 5/9/24, PRS voted unanimously to endorse and forward to TAC the 4/5/24 PRS Report and 3/20/24 Impact Analysis for NPRR1222. All Market Segments participated in the vote.
Summary of PRS Discussion	On 4/5/24, ERCOT Staff provided an overview of NPRR1222 and confirmed that under NPRR1222 the annual Ancillary Service methodology review process would commence earlier in the calendar year to accommodate PUCT approval by the end of year. On 5/9/24, there was no discussion.
TAC Decision	On 5/22/24, TAC voted unanimously to recommend approval of NPRR1222 as recommended by PRS in the 5/9/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, 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

Board Report

	☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1222 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1222 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 NPRR1222.
ERCOT Opinion	ERCOT supports approval of NPRR1222.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1222 and believes the market impact for NPRR1222 appropriately incorporates the PUCT into the approval structure of the Ancillary Service methodology Other Binding Document.

Sponsor	
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Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
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Board Report

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Please note the baseline Protocol language in Section 3.16 has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1213, Allow DGRs and DESRs on Circuits Subject to Load Shed to Provide ECRS and Clarify Language Regarding DGRs and DESRs Providing Non-Spin (incorporated 5/1/24)

Proposed Protocol Language Revision

3.16 Standards for Determining Ancillary Service Quantities

(1) ERCOT shall comply with the requirements for determining Ancillary Service quantities as specified in these Protocols and the ERCOT Operating Guides.

(2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the quantity requirements for each Ancillary Service needed for reliability, including:

(a) The percentage or MW limit of ERCOT Contingency Reserve Service (ECRS) allowed from Load Resources providing ECRS;

(b) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR);

[NPRR1128: Replace item (b) above with the following upon system implementation:]

(b) The maximum amount (MW) of Responsive Reserve (RRS) that can be provided by Resources capable of Fast Frequency Response (FFR) and specify the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability;

(c) The maximum amount (MW) of Regulation Up Service (Reg-Up) that can be provided by Resources providing Fast Responding Regulation Up Service (FRRS-Up); and

(d) The maximum amount (MW) of Regulation Down Service (Reg-Down) that can be provided by Resources providing Fast Responding Regulation Down Service (FRRS-Down).

[NPRR1007: Delete items (c) and (d) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(e) The minimum capacity required from Resources providing RRS using Primary Frequency Response shall not be less than 1,150 MW.

(3) The ERCOT Board shall review and recommend approvale of ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from SCED dispatchable Resources to provide Non-Spin, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, and the maximum amount of Reg-Up and Reg-Down that can be provided by Resources providing FRRS-Up and FRRS-Down. Any such recommendations require approval by the Public Utility Commission of Texas (PUCT) prior to implementation.

[NPRR1007, NPRR1128, NPRR1171, NPRR1183, and NPRR1213: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1007; or upon system implementation for NPRR1128, NPRR1171, or NPRR1183; or upon system implementation and upon system implementation of NPRR1171 for NPRR1213:]

(3) The ERCOT Board shall review and recommend approvale of ERCOT's methodology for determining the minimum Ancillary Service requirements, any minimum capacity required from Security-Constrained Economic Dispatch (SCED) dispatchable Resources to provide Non-Spinning Reserve (Non-Spin), the maximum amount of Non-Spin that can be provided by Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) that are interconnected to a distribution circuit that is subject to Load shed, the maximum amount of ECRS that can be provided by DGRs and DESRs that are interconnected to a distribution circuit that is subject to Load shed, the minimum capacity required from Resources providing Primary Frequency Response to provide RRS, the maximum amount of RRS that can be provided by Resources capable of FFR, and the Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability. ERCOT shall post on the ERCOT website the ERCOT Methodologies for Determining Minimum Ancillary Service Requirements approved by the ERCOT Board. Any such recommendations require approval by the Public Utility Commission of Texas (PUCT) prior to implementation.

(4) If ERCOT determines a need for additional Ancillary Service Resources under these Protocols or the ERCOT Operating Guides, after an Ancillary Service Plan for a specified day has been posted, ERCOT shall inform the market by posting notice on the ERCOT website, of ERCOT's intent to procure additional Ancillary Service Resources under Section 6.4.9.2, Supplemental Ancillary Services Market. ERCOT shall post the reliability reason for the increase in service requirements.

[NPRR1007: Delete paragraph (4) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(5) Monthly, ERCOT shall determine and post on the Market Information System (MIS) Secure Area a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR shall be limited to 60% of the total ERCOT RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed.

[NPRR1128 and NPRR1183: Replace applicable portions of paragraph (5) above with the following upon system implementation:]

(5) Monthly, ERCOT shall determine and post on the ERCOT website a minimum capacity required from Resources providing RRS using Primary Frequency Response. The remaining capacity required for RRS may be supplied by all Resources qualified to provide RRS, provided that RRS from Load Resources on high-set under-frequency relays and Resources providing FFR shall be limited to 60% of the total ERCOT RRS requirement. ERCOT may increase the minimum capacity required from Resources providing RRS using Primary Frequency Response if it believes that the current posted quantity will have a negative impact on reliability or if it would require additional Regulation Service to be deployed. ERCOT may add more Operating Hours where prioritizing procurement of FFR up to the maximum FFR amount is beneficial in improving reliability if it believes that these additional hours are vulnerable to low system inertia. ERCOT will issue an operations notice when such a change is made.

(6) The amount of RRS that a Qualified Scheduling Entity (QSE) can self-arrange using a Load Resource excluding Controllable Load Resources and Resources providing FFR is limited to its Load Ratio Share (LRS) of the capacity allowed to be provided by Resources not providing RRS using Primary Frequency Response established in paragraph (5) above, provided that RRS from these Resources shall be limited to 60% of the total ERCOT RRS requirement.

(7) However, a QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of RRS to other Market Participants. The total amount of RRS using the Load Resource procured by ERCOT is also limited to the capacity established in paragraph (5) above, up to the lesser of the 60% limit or the limit established by ERCOT in paragraph (5) above.

(8) Monthly, ERCOT shall determine and post on the MIS Secure Area a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding

Controllable Load Resources that may or may not be on high-set under-frequency relays providing ECRS is limited to 50% of the total ERCOT ECRS requirement.

[NPRR1183: Replace paragraph (8) above with the following upon system implementation:]

(8) Monthly, ERCOT shall determine and post on the ERCOT website a minimum capacity required from Resources providing ECRS. The amount of Load Resources excluding Controllable Load Resources that may or may not be on high-set under-frequency relays providing ECRS is limited to 50% of the total ERCOT ECRS requirement.

(9) The amount of ECRS that a QSE can self-arrange using a Load Resource excluding Controllable Load Resources is limited to the lower of:

(a) 50% of its ECRS Ancillary Service Obligation; or

(b) A reduced percentage of its ECRS Ancillary Service Obligation based on the limit established by ERCOT in paragraph (8) above.

(10) A QSE may offer more of the Load Resource above the percentage limit established by ERCOT for sale of ECRS to other Market Participants. The total amount of ECRS using the Load Resource excluding Controllable Load Resources procured by ERCOT is also limited to the lesser of the 50% limit or the limit established by ERCOT in paragraph (9) above.

(11) The maximum MW amount of capacity from Resources providing FRRS-Up is limited to 65 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(12) The maximum MW amount of capacity from Resources providing FRRS-Down is limited to 35 MW. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation Service to be deployed.

(13) Resources can only provide FRRS-Up or FRRS-Down if awarded Regulation Service in the Day-Ahead Market (DAM) for that particular Resource, up to the awarded quantity.

[NPRR1007: Delete paragraphs (11)-(13) above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

ERCOT Impact Analysis Report

NPRR Number	1222	NPRR Title	Public Utility Commission of Texas Approval of the Methodology for Determining Ancillary Service Requirements
Impact Analysis Date		March 20, 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	1223	NPRR Title	Addition of TA Contact Information Into TDSP Application Form
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Normal	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		The first of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		23 Form J, Transmission and/or Distribution Service Provider Application for Registration	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Protocol Revision Request (NPRR) updates Section 23, Form J to require Transmission and/or Distribution Service Providers (TDSPs) to provide contact information to ERCOT.	
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	

Board Report

	☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	ERCOT currently collects Transition/Acquisition ("TA") contact information in Section 23, Form B, Load Serving Entity (LSE) Application for Registration, which is helpful for ERCOT to have in the event of a Mass Transition or acquisition transfer. However, if ERCOT needs to contact a TDSP during such an event, there is not a dedicated contact. ERCOT has typically contacted the TDSP's Authorized Representative (AR) or Backup AR in these situations, but that contact is often not the contact who works on Mass Transitions or acquisition transfers. Having designated TA contacts for the TDSPs is beneficial to ensure the correct people are timely receiving the important information related to the transitions.
PRS Decision	On 4/5/24, PRS voted unanimously to recommend approval of NPRR1223 as submitted. All Market Segments participated in the vote. On 5/9/24, PRS voted unanimously to endorse and forward to TAC the 4/5/24 PRS Report as revised by PRS and 3/21/24 Impact Analysis for NPRR1223.
Summary of PRS Discussion	On 4/5/24, PRS reviewed NPRR1223. On 5/9/24, edits were made to Section 9, Transition/Acquisition ("TA"), to align with NPRR1206, Revisions to QSE Operations and Termination Requirements, and Elimination of Providing Certain Market Participant Principal Information.
TAC Decision	On 5/22/24, TAC voted unanimously to recommend approval of NPRR1223 as recommended by PRS in the 5/9/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable)

Board Report

	☐ Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted unanimously to recommend approval of NPRR1223 as recommended by TAC in the 5/22/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1223 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	The Independent Market Monitor (IMM) has no opinion on NPRR1223.
ERCOT Opinion	ERCOT supports approval of NPRR1223.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1223 and believes that it provides a positive market impact by embodying Strategic Plan Objective 1 by updating Section 23, Form J to require TDSPs to provide contact information to ERCOT for use during a Mass Transition or acquisition transfer.

Sponsor	
Name	Katherine Gross / Sarah Heselmeyer
E-mail Address	Katherine.Gross@ercot.com / Sarah.Heselmeyer@ercot.com
Company	ERCOT
Phone Number	512-225-7184 / 512-248-3952
Cell Number	216-224-3943
Market Segment	Not Applicable

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

Comments Received

Comment Author	Comment Summary
None	

Market Rules Notes

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

- NPRR1206, Revisions to QSE Operations and Termination Requirements, and Elimination of Providing Certain Market Participant Principal Information (incorporated 5/1/24)
  - Section 23, Form J

Proposed Protocol Language Revision

ERCOT Nodal Protocols

Section 23

Form J: Transmission and/or Distribution Service Provider Application for Registration

~~April 1, 2023~~**TBD**

Date Received: _____

TRANSMISSION AND/OR DISTRIBUTION SERVICE PROVIDER (TDSP)
APPLICATION FOR REGISTRATION

This application is for approval as a Transmission Service Provider (TSP), Distribution Service Provider (DSP), or both TSP and DSP by Electric Reliability Council of Texas, Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. ERCOT will accept the completed, executed application via email to MPRegistration@ercot.com (.pdf version). In addition to the application, ERCOT must receive an application fee in the amount of $500 via Electronic Funds Transfer (EFT) (wire or Automated Clearing House (ACH)). All payments should reference the applicant's name and Data Universal Numbering System (DUNS) Number (DUNS #) in the remarks. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application must be signed by the Authorized Representative ("AR"), Backup Authorized Representative or an Officer of the company listed herein, as appropriate. ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

PART I – COMPANY INFORMATION

Legal Name of the Applicant:	
Legal Address of the Applicant:	Street Address:
	City, State, Zip:
DUNS[1] Number:	

[1]Defined in Section 2.1, Definitions.

Type: TSP ☐ DSP ☐ Both ☐ as reflected on Standard Form Agreement

1. Authorized Representative ("AR"). Defined in Section 2.1, Definitions.

Name:	
Telephone:	
Email Address:	

2. Backup AR. *(Optional)* This person may sign any form for which an AR's signature is required and will perform the functions of the AR in the event the AR is unavailable.

Name:	
Telephone:	
Email Address:	

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual ☐ Partnership ☐ Municipally Owned Utility
☐ Electric Cooperative ☐ Limited Liability Company ☐ Corporation
☐ Other: _____

If Applicant is not an individual, provide the state in which the Applicant is organized, _____, and the date of organization: _____

4. User Security Administrator (USA). As defined in Section 16.12, User Security Administrator and Digital Certificates, the USA is responsible for managing the Market Participant's access to ERCOT's computer systems through Digital Certificates.

Name:	
Telephone:	
Email Address:	

4a. ☐ By checking this box, Applicant hereby requests that ERCOT evaluate Applicant's eligibility to opt out of the requirement that Market Participant designate a USA and receive Digital Certificates, and affirms the following:

(a) Applicant is applying to register with ERCOT as either a Municipally Owned Utility (MOU) or an Electric Cooperative (EC), and as a DSP and/or Load Serving Entity (LSE).

(b) Applicant is not, and will not, be designated as a Transmission Operator (TO) with ERCOT.

(c) Applicant understands that by opting out, it will not be granted access to portions of the ERCOT Market Information System (MIS) that require Digital Certificate Access.

(d) Applicant understands that it can cancel any approved opt-out request, designate a USA, and begin receiving Digital Certificates by properly completing Section 23, Form E, Notice of Change of Information, and meeting the requirements under Section 16.12.

(e) If determined ineligible, Applicant must designate a USA, receive Digital Certificates and comply with requirements under Protocol Section 16.12.

5. Backup USA. *(Optional)* This person may perform the functions of the USA as defined in the ERCOT Protocols in the event the USA is unavailable.

Name:	
Telephone:	
Email Address:	

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:	
Telephone:	

Email Address:	

7. TSP 24x7 Control or Operations Center. As defined in the ERCOT Protocols, the 24x7 Control or Operations Center is responsible for operational communications and shall have sufficient authority to commit and bind the TSP.

Desk Name:					
Address:					
City:		State:		Zip:	
Telephone:		Fax:			
Email Address:					

8. Compliance Contact. This person is responsible for compliance related issues.

Name:	
Telephone:	
Email Address:	

9. Transition/Acquisition ("TA"). Responsible for coordinating Mass TA events between ERCOT, Competitive Retailers (CRs), and LSEs. Includes TA Business ("TAB"), TA Regulatory ("TAR") and TA Technical ("TAT").

TAB:

Name:	_____	~~Title:~~	_____		
~~Address:~~	_____				
~~City:~~	_____	~~State:~~	_____	~~Zip:~~	_____
Telephone:	_____	~~Fax:~~	_____		
Email Address:	_____				

TAR:

Name:	_____	~~Title:~~	_____		
~~Address:~~	_____				
~~City:~~	_____	~~State:~~	_____	~~Zip:~~	_____
Telephone:	_____	~~Fax:~~	_____		
Email Address:	_____				

TAT:

Name:	_____	~~Title:~~	_____		
~~Address:~~	_____				
~~City:~~	_____	~~State:~~	_____	~~Zip:~~	_____
Telephone:	_____	~~Fax:~~	_____		
Email Address:	_____				

PART II – ASSET REGISTRATION

1. Provide Generation Load Metering Point and TDSP Read Generation information as required on the ERCOT Generation Load Metering Point(s) & TDSP Read Generation Registration Form. The form is located at http://www.ercot.com/services/rq/tdsp/index.html. The completed form should be attached to, and submitted with, the TDSP Registration Application.

2. Provide status of registering MOU or EC:

☐ **Opt-In MOU or EC** – An EC or MOU that offers Customer Choice.

☐ **Non-Opt-In Entity (NOIE)** – An EC or MOU that does not offer Customer Choice.

PART III – ADDITIONAL REQUIRED INFORMATION

1. Officers. ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State as having binding authority for the Applicant. ERCOT will use this list of individuals to determine who can execute such documents as the Standard Form Market Participant Agreement (Section 22, Attachment A), Amendment to Standard Form Market Participant Agreement (Section 22, Attachment C), Digital Certificate Audit Attestation (DCAA), etc. Alternatively, additional documentation (Articles of Incorporation, Board Resolutions, Delegation of Authority, Secretary's Certificate, etc.) can be provided to prove binding authority for the Applicant.

2. Affiliates and other Registrations. Provide the name, legal structure, and relationship of each of the Applicant's affiliates, if applicable. See Section 2.1, Definitions, for the definition of "Affiliate." Please also provide the name and type of any other ERCOT Market Participant registrations held by the Applicant. *(Attach additional pages if necessary.)*

Affiliate Name (or name used for other ERCOT registration)	**Type of Legal Structure** (partnership, limited liability company, corporation, etc.)	**Relationship** (parent, subsidiary, partner, affiliate, etc.)

PART IV – SIGNATURE

I affirm that I have personal knowledge of the facts stated in this application and that I have the authority to submit this application form on behalf of the Applicant. I further affirm that all statements made and information provided in this application form are true, correct and complete, and that the Applicant will provide to ERCOT any changes in such information in a timely manner.

Signature of AR, Backup AR or Officer:	
Printed Name of AR, Backup AR or Officer:	
Date:	

ERCOT Impact Analysis Report

NPRR Number	1223	NPRR Title	Addition of TA Contact Information Into TDSP Application Form
Impact Analysis Date		March 21, 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		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

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

Comments
None.

Board Report

NPRR Number	1224	NPRR Title	ECRS Manual Deployment Triggers
Date of Decision		June 18, 2024	
Action		Recommended Approval	
Timeline		Urgent - to implement the policy approach proposed herein by summer 2024.	
Estimated Impacts		Cost/Budgetary: None Project Duration: No project required	
Proposed Effective Date		The first of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Nodal Protocol Sections Requiring Revision		6.4.4.3, Energy Offer Curve for On-Line ERCOT Contingency Reserve Capacity (new) 6.5.7.3, Security Constrained Economic Dispatch 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Protocol Revision Request (NPRR) introduces a trigger that ERCOT may use to manually release ERCOT Contingency Reserve Service (ECRS) from Security-Constrained Economic Dispatch (SCED)-dispatchable Resources when the system power balance constraint is consistently violated and the MW amount of the power balance violation is at least 40 MW for ten consecutive minutes. This NPRR also requires that the Energy Offer Curves for the capacity assigned to ECRS be offered at no less than $750 per MWh.	
Reason for Revision		[X] 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	

Board Report

	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	During the 2024 Ancillary Service methodology discussion at meetings of the Technical Advisory Committee (TAC) and the ERCOT Board of Directors (ERCOT Board), ERCOT was asked to review the methodology used to compute the minimum quantities of ECRS and identify potential alternatives by April 30, 2024, taking into account the analysis that the Independent Market Monitor (IMM) has conducted on the impact of ECRS. This timeline was selected so that proposed changes (if necessary) could be in place by summer 2024. ERCOT and the IMM have been working on this issue. The IMM recommended a few changes to alleviate its concerns. ERCOT has closely reviewed these recommendations. One proposal was to require ERCOT to release some portion of ECRS in every hour at an energy offer floor via a standing deployment. ERCOT is agreeable to this proposal but notes that this concept may need some system changes (potentially both for systems at ERCOT and on the Market Participant end) and may not be feasible to implement by summer 2024. Another IMM proposal was to allow ERCOT to manually release ECRS capacity from SCED-dispatchable Resources when the power balance constraint is violated. ERCOT has worked with the IMM to develop this concept further in a manner that would allow it to be implemented by summer 2024. Based on that work, this NPRR proposes to include a trigger that will allow manually releasing ECRS capacity on SCED-dispatchable Resources when the power balance constraint is consistently violated and the MW amount of the power balance violation is at least 40 MW for ten consecutive minutes. ERCOT is open to stakeholder comments regarding alternative values of power balance violation and duration. When manually releasing SCED-dispatchable ECRS, ERCOT plans to preserve some SCED-dispatchable ECRS to ensure that ERCOT has sufficient capacity that can respond and help recover frequency within the parameters required by North American Electric Reliability Corporation (NERC) Reliability Standards. However, if the power balance constraint violation remains at or above 40 MW, ERCOT will continue to release ECRS in small blocks.

	Further, when ECRS capacity from SCED-dispatchable Resources is manually released, ERCOT will recall the manually released ECRS when the triggering condition has ended and the ERCOT System is operating with a steady-state frequency above 59.97 Hz.
PRS Decision	On 4/5/24, PRS voted to grant NPRR1224 Urgent status. There were two opposing votes from the Cooperative (LCRA) and Independent Generator (Calpine) Market Segments and two abstentions from the Independent Power Marketer (IPM) (2) (Tenaska, Morgan Stanley) Market Segments. PRS then voted to table NPRR1224. There were three abstentions from the Cooperative (PEC), Independent Generator (Jupiter Power), and Investor Owned Utility (IOU) (Oncor) Market Segments. All Market Segments participated in both votes. On 5/9/24, PRS voted to recommend approval of NPRR1224 as amended by the 4/30/24 TCPA comments as revised by PRS and to forward to TAC NPRR1224 and the 3/27/24 Impact Analysis. There were five opposing votes from the Consumer (4) (Residential, OPUC, City of Eastland, Occidental) and Independent Retail Electric Provider (IREP) (Reliant) Market Segments and six abstentions from the Cooperative (2) (STEC, PEC), Independent Generator (NextEra Energy), and Municipal (3) (CPS Energy, GEUS, Austin Energy) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 4/5/24, ERCOT Staff provided an overview of NPRR1224 and the request for Urgent status. Participants reviewed the issues raised in the 4/4/24 Joint Consumers comments and requested additional analysis from the IMM and ERCOT prior to moving NPRR1224 forward. On 5/9/24, participants reviewed the 4/30/24 TCPA comments, debated the appropriateness of a price floor for ECRS and an appropriate value for it, and proposed desktop edits to the Revision Description to align with the Protocol revisions.
TAC Decision	On 5/22/24, TAC voted to recommend approval of NPRR1224 as recommended in the 5/9/24 PRS Report as revised by TAC. There were ten opposing votes from the Consumer (6) (Residential, OPUC, CMC Steel, Lyondell Chemical, City of Eastland, City of Dallas) and IREP (4) (Reliant, Rhythm Ops, APG&E, Demand Control 2) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/22/24, TAC reviewed the items below. Participants reviewed the 5/15/24 and 5/17/24 IMM comments, and debated the appropriateness of a price floor for ECRS and an appropriate value for it. Participants proposed desktop edits to lower the floor from the PRS-recommended value of $1,000 per MWh to $750 per MWh.

Explanation of Opposing TAC Votes	**Consumer/Residential, OPUC** – We agree with Lyondell Chemical's perspective on the IMM's comments, and also appreciate that the NPRR will lead to an earlier deployment of ECRS, which will allow the reserved capacity to meet the energy demands of ERCOT's consumers more efficiently. While an offer floor is inappropriate, if the ERCOT Board were to approve the NPRR with an offer floor, it should be in the range of $200 instead of $750. $200 is a little above the Non-Spin offer floor. **Consumer/CMC Steel** – We support the IMM's comments and believe that a price floor, particularly a price floor as high as $750/MWh, is inappropriate. The price floor merely maintains market inefficiencies that this NPRR was meant to address. As the IMM explained, while it may be in the economic interest of suppliers in the short term, artificially setting prices so high will undermine the credibility of the ERCOT market. **Consumer/Lyondell Chemical** – We voted against the current language in NPRR1224 because its high price floor will impose needlessly high costs on ERCOT consumers. We note that during the highest Load hours during summer peak, there is no need for ERCOT to procure so much ECRS, as the ERCOT market design already provides overwhelming incentives for the ERCOT bilateral commercial market to make all available resources ready for real-time dispatch. As NPRR1224 currently stands, the price floor of $750/MWh will interact with this artificial shortage of dispatchable Resources created by high levels of ECRS procurement during summer peak to burden ERCOT consumers with excessive costs. We support the IMM's comments and believe that a price floor, particularly a price floor as high as $750/MWh, is inappropriate. The price floor merely maintains market inefficiencies that this NPRR was meant to address. As the IMM explained, while it may be in the economic interest of suppliers in the short term, artificially setting prices so high will undermine the credibility of the ERCOT market. Notably, a price floor at $750 is not backed by any robust analysis. The Joint Commenters attempt to equate a 500 MW release of ECRS to a 500 MW shortage, which the IMM explained was improper because it's not clear how much of the ECRS will be dispatched. Without a more thorough analysis, implementing a $750/MWh price floor will only serve to maintain market inefficiencies at the expense of consumers. **Consumer/City of Eastland, City of Dallas** – The $750 price floor is excessive and undermines the purpose of NPRR1224—to reduce the $12 billion of ECRS related artificial shortage prices. As the IMM commented, a price floor retains significant levels of artificial shortage prices that exceed the floor. Moreover, there is insufficient analysis demonstrating the price floor, at such a high threshold, appropriately values ECRS. In sum, the price floor (1) reinforces market

	inefficiencies that NPRR1224 intends to address, and (2) lacks analytical support. Thus, NPRR1224—with the $750 price floor—imposes unnecessary and unsubstantiated cost on consumers. **IREP/Reliant** – Reliant opposes the level of offer price floor at $750 and whether that high of a floor could offset the benefits of releasing portions of ECRS earlier for "undergen" conditions. Reliant has concerns with the excessive amount of Ancillary Service procurement given the overlap in objectives between ECRS and Non-Spin to address net Load variability. We understand the need to value reserves consistent with the reliability benefits provided to the ERCOT System but establishing price floor levels at this time pre-empts the process to perform a comprehensive review of the Ancillary Service methodology and procurement amounts at the PUCT. **IREP/Rhythm Ops** – Rhythm opposes for the same reasons as Reliant and would prefer no floor for the reasons above. That said, the discussions at TAC (particularly the graphs presented by the Joint Commenters) indicated that even if ECRS is being used to support conservative operations, a $500 floor was a more appropriate read of the data. **IREP/APG&E** – Explanation requested but not provided. **IREP/Demand Control 2** – Demand Control 2 agrees with the comments of Reliant and Rhythm Ops above.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 6/18/24, the ERCOT Board voted to recommend approval of NPRR1224 as recommended by TAC in the 5/22/24 TAC Report. There was one abstention.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1224 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.

Board Report

Independent Market Monitor Opinion	See 5/15/24, 5/17/24, 6/4/24, and 6/12/24 IMM comments
ERCOT Opinion	ERCOT supports approval of NPRR1224.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1224 and believes the market impact for NPRR1224 provides an additional trigger that the ERCOT Control Room Operators may use to manage the release of ECRS Capacity to SCED in the near term, but acknowledges longer-term solutions will be proposed in subsequent NPRR(s).

Sponsor	
Name	Nitika Mago
E-mail Address	nitika.mago@ercot.com
Company	ERCOT
Phone Number	512-248-6601
Cell Number	
Market Segment	Not applicable

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

Comments Received	
Comment Author	**Comment Summary**
Joint Consumers 040424	Opposed Urgent status for NPRR1224 and requested additional backcast analysis of 2023 under NPRR1224 from the IMM and ERCOT in the near term, and a comprehensive review of the ECRS methodology in the longer term
TCPA 042024	Proposed additional revisions, including the addition of a price floor and raising the trigger from 30 MW to 40 MW
TCPA 043024	Proposed additional revisions on top of the 4/20/24 TCPA comments based on feedback received

IMM 051524	Expressed concerns with the PRS-recommended version of NPRR1224 and argued against an offer price floor for ECRS
IMM 051724	Provided additional revisions to eliminate the proposed offer price floor
Joint Commenters 052024	Responded to the 5/15/24 IMM comments and 5/17/24 IMM comments to identify wo fundamental differences between the 5/9/22 PRS recommendation and the IMM approach, first as whether price reversal is appropriate when Ancillary Service reserves are released for energy, and second as how to reflect the value of foregone Ancillary Service reserves
IMM 060424	Provided additional revisions to the 5/22/24 TAC Report lowering the offer price floor to $100 and lowering the trigger to 5 MW
Aspire Power Ventures 060624	Expressed concerns with the TAC-recommended version of NPRR1224 which includes the $750 offer price floor and suggested that if an offer price floor is included, it should be somewhere between $25 and $250
Joint Consumers 061024	Expressed concerns with the TAC-recommended offer price floor of $750 and suggested that an offer price floor of $100 would be more appropriate
Joint Commenters 061024	Provided supporting analysis and expressed support for the TAC-recommended version of NPRR1224
IMM 061224	Responded to issues raised within the 6/10/24 Joint Commenters comments
ERCOT 061524	Provided a list of the ECRS deployments that have occurred since ECRS was implemented in June 2023 through May 2024

Market Rules Notes

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

- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
  - Section 6.5.7.3

Proposed Protocol Language Revision

6.4.4.3 Energy Offer Curve for On-Line ERCOT Contingency Reserve Capacity

(1) The following applies to Generation Resources that a QSE assigns ERCOT Contingency Reserve Service (ECRS) Ancillary Service Resource Responsibility in its COP to meet the QSE's Ancillary Service Supply Responsibility for ECRS and applies to On-Line ECRS assignments arising as the result of Day-Ahead Market (DAM) or Supplemental Ancillary Services Market (SASM) Ancillary Service awards, or Self-Arranged Ancillary Service Quantity.

(a) Prior to the end of the Adjustment Period for an Operating Hour during which a Generation Resource is assigned On-Line ECRS Ancillary Service Resource Responsibility, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to ECRS may not be offered at less than $~~1,00~~750 per MWh.

[NPRR1058: Replace paragraph (a) above with the following upon system implementation:]

(a) For an Operating Hour during which a Generation Resource is assigned On-Line ECRS Ancillary Service Resource Responsibility, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves submitted by the QSE for the capacity assigned to ECRS may not be offered at less than $~~1,00~~750 per MWh.

(b) Prior to the end of the Adjustment Period for an Operating Hour during which a Controllable Load Resource is assigned ECRS Ancillary Service Resource Responsibility, the QSE shall ensure that an Energy Bid Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Bid Curve submitted by the QSE for the capacity assigned to ECRS may not be less than $~~1,00~~750 per MWh.

[NPRR1058: Replace paragraph (b) above with the following upon system implementation:]

(b) For an Operating Hour during which a Controllable Load Resource is assigned ECRS Ancillary Service Resource Responsibility, the QSE shall ensure that an Energy Bid Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Bid Curve submitted by the QSE for the capacity assigned to ECRS may not be less than $~~1,00~~750 per MWh.

(~~cb~~) If the QSE also assigns Responsive Reserve (RRS) and/or Regulation Up Service (Reg-Up) to a Generation Resource that has been assigned ECRS, the QSE shall ensure that a valid Output Schedule or Energy Offer Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Offer Curves

submitted by the QSE for the capacity assigned to the sum of the RRS, ECRS, and Reg-Up, as well as any Non-Frequency Responsive Capacity (NFRC) that is above the Resource's High Ancillary Service Limit (HASL) and will not be utilized prior to deployment of a Resource's ECRS, may not be offered at less than $~~1,007~~50 per MWh.

(d) If the QSE also assigns RRS, and/or Reg-Up to a Controllable Load Resource that has been assigned ECRS, the QSE shall ensure that a valid Energy Bid Curve for the Operating Hour has been submitted and accepted by ERCOT. The Energy Bid Curves submitted by the QSE for the capacity assigned to the sum of the RRS, ECRS and Reg-Up Ancillary Service Resource Responsibilities may not be less than $~~100~~750 per MWh.

[NPRR1010: Delete Section 6.4.4.3 above upon system implementation of the Real-Time Co-Optimization (RTC) project.]

6.5.7.3 Security Constrained Economic Dispatch

Commented [CP1]: Please note NPRR1188 also proposes revisions to this section.

(1) The SCED process is designed to simultaneously manage energy, the system power balance and network congestion through Resource Base Points and calculation of LMPs every five minutes. The SCED process uses a two-step methodology that applies mitigation prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Output Schedules and Real-Time Market (RTM) Energy Bids to determine Resource Dispatch Instructions by maximizing bid-based revenues minus offer-based costs, subject to power balance and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.

(2) The SCED solution must monitor cumulative deployment of Regulation Services and ensure that Regulation Services deployment is minimized over time.

(3) In the Generation To Be Dispatched (GTBD) determined by LFC, ERCOT shall subtract the sum of the telemetered net real power consumption from all Controllable Load Resources available to SCED.

(4) For use as SCED inputs, ERCOT shall use the available capacity of all committed Generation Resources by creating proxy Energy Offer Curves for certain Resources as follows:

(a) Non-IRRs and Dynamically Scheduled Resources (DSRs) without Energy Offer Curves

(i) ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below for:

(A) Each non-IRR for which its QSE has submitted an Output Schedule instead of an Energy Offer Curve; and

(B) Each DSR that has not submitted incremental and decremental Energy Offer Curves.

MW	Price (per MWh)
HSL	SWCAP
Output Schedule MW plus 1 MW	SWCAP minus $0.01
Output Schedule MW	-$249.99
LSL	-$250.00

(b) DSRs with Energy Offer Curves

(i) For each DSR that has submitted incremental and decremental Energy Offer Curves, ERCOT shall create a monotonically increasing proxy Energy Offer Curve. That curve must consist of the incremental Energy Offer Curve that reflects the available capacity above the Resource's Output Schedule to its HSL and the decremental Energy Offer Curve that reflects the available capacity below the Resource's Output Schedule to the LSL. The curve must be created as described below:

MW	Price (per MWh)
Output Schedule MW plus 1 MW to HSL	Incremental Energy Offer Curve
LSL to Output Schedule MW	Decremental Energy Offer Curve

(c) Non-IRRs without full-range Energy Offer Curves

(i) For each non-IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the Resource's available capacity, ERCOT shall create a proxy Energy Offer Curve that extends the submitted Energy Offer Curve to use the entire available capacity of the Resource above the highest point on the Energy Offer Curve to the Resource's HSL and the offer floor from the lowest point on the Energy Offer Curve to its LSL, using these points:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

(d) IRRs

(i) For each IRR that has not submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	$1,500
HSL minus 1 MW	-$249.99
LSL	-$250.00

(ii) For each IRR for which its QSE has submitted an Energy Offer Curve that does not cover the full range of the IRR's available capacity, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in submitted Energy Offer Curve)	Price associated with the highest MW in submitted Energy Offer Curve
Energy Offer Curve	Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

(e) RUC-committed Resources

(i) For each RUC-committed Resource that has not submitted an Energy Offer Curve, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	$250
Zero	$250

(ii) For each RUC-committed Resource that has submitted an Energy Offer Curve, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in Energy Offer Curve)	Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve

Energy Offer Curve	Greater of $250 or the QSE submitted Energy Offer Curve
Zero	Greater of $250 or the first price point of the QSE submitted Energy Offer Curve

(iii) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	**Price (per MWh)**
HSL of RUC-committed configuration	$250
Zero	$250

(iv) For each Combined Cycle Generation Resource that was RUC-committed from one On-Line configuration in order to transition to a different configuration with additional capacity, as instructed by ERCOT, that has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a monotonically increasing proxy Energy Offer Curve as described below:

MW	**Price (per MWh)**
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of $250 or the QSE submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than $250)	$250
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE submitted Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

~~*[NPRR1224: Insert paragraph (f) below upon system implementation:]*~~

~~(f) Generation Resources carrying On-Line ECRS capacity~~

~~(i) For each Generation Resource carrying On-Line ECRS capacity, ERCOT shall adjust the submitted or proxy Energy Offer Curve as described above in the manner described below:~~

~~MW~~	~~Price (per MWh)~~
~~HSL~~	~~Greater of $1000, or the proxy Energy Offer Curve as described in paragraph (4) (a) (e) above, or the originally submitted Energy Offer Curve.~~
~~HSL less the sum of the RRS, ECRS, and Reg-Up, as well as any Non-Frequency Responsive Capacity (NFRC) that is above the Resource's High Ancillary Service Limit (HASL) and will not be utilized prior to deployment of a Resource's ECRS~~	~~Greater of $1000, or the proxy Energy Offer Curve as described in paragraph (4) (a) (e) above, or the originally submitted Energy Offer Curve.~~

(5) The Entity with decision making authority, as more fully described in Section 3.19.1, Constraint Competitiveness Test Definitions, over how a Resource or Split Generation Resource is offered or scheduled, shall be responsible for all offers associated with each Resource, including offers represented by a proxy Energy Offer Curve.

(6) For a Controllable Load Resource whose QSE has submitted an RTM Energy Bid that does not cover the full range of the Resource's available Demand response capability, consistent with the Controllable Load Resource's telemetered quantities, ERCOT shall create a proxy energy bid as described below:

MW	Price (per MWh)
LPC to MPC minus maximum MW of RTM Energy Bid	Price associated with the lowest MW in submitted RTM Energy Bid curve
MPC minus maximum MW of RTM Energy Bid to MPC	RTM Energy Bid curve
MPC	Right-most point (lowest price) on RTM Energy Bid curve

(7) ERCOT shall ensure that any RTM Energy Bid is monotonically non-increasing. The QSE representing the Controllable Load Resource shall be responsible for all RTM Energy Bids, including bids updated by ERCOT as described above.

(8) If a Controllable Load Resource telemeters a status of OUTL, it is not considered as dispatchable capacity by SCED. A QSE may use this function to inform ERCOT of instances when the Controllable Load Resource is unable to follow SCED Dispatch Instructions. Under all telemetered statuses including OUTL, the remaining telemetry quantities submitted by the QSE shall represent the operating conditions of the Controllable Load Resource that can be verified by ERCOT. A QSE representing a Controllable Load Resource with a telemetered status of OUTL is still obligated to provide any applicable Ancillary Service Resource Responsibilities previously awarded to that Controllable Load Resource. This paragraph does not apply to ESRs.

(9) Energy Offer Curves that were constructed in whole or in part with proxy Energy Offer Curves shall be so marked in all ERCOT postings or references to the energy offer.

(10) The two-step SCED methodology referenced in paragraph (1) above is:

(a) The first step is to execute the SCED process to determine Reference LMPs. In this step, ERCOT executes SCED using the full Network Operations Model while only observing limits of Competitive Constraints. Energy Offer Curves for all On-Line Generation Resources and RTM Energy Bids from available Controllable Load Resources, whether submitted by QSEs or created by ERCOT under this Section, are used in the SCED to determine "Reference LMPs."

(b) The second step is to execute the SCED process to produce Base Points, Shadow Prices, and LMPs, subject to security constraints (including Competitive and Non-Competitive Constraints) and other Resource constraints. The second step must:

(i) Use Energy Offer Curves for all On-Line Generation Resources, whether submitted by QSEs or created by ERCOT. Each Energy Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. In addition, each Energy Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed 0.01 multiplied by the value of the Resource's Mitigated Offer Cap (MOC) curve at the LSL or the appropriate MOC;

(ii) Use RTM Energy Bid curves for all available Controllable Load Resources, whether submitted by QSEs or created by ERCOT. There is no mitigation of RTM Energy Bids. An RTM Energy Bid from a Controllable Load Resource represents the bid for energy distributed across all nodes in the Load Zone in which the Controllable Load Resource is located. For an ESR, an RTM Energy Bid represents a bid for energy at the ESR's Resource Node; and

(iii) Observe all Competitive and Non-Competitive Constraints.

(c) ERCOT shall archive information and provide monthly summaries of security violations and any binding transmission constraints identified in Step 2 of the SCED process. The summary must describe the limiting element (or identified operator-entered constraint with operator's comments describing the reason and the Resource-specific impacts for any manual overrides). ERCOT shall provide the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).

(11) For each SCED process, in addition to the binding Base Points and LMPs, ERCOT shall calculate a non-binding projection of the Base Points and Resource Node LMPs, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs at a frequency of every five minutes for at least 15 minutes into the future based on the same inputs to the SCED process as described in this Section, except that the Resource's HDL and LDL and the total generation requirement will be as estimated at future intervals. The Resource's HDL and LDL will be calculated for each interval of the projection based on the ramp rate capability over the study period. ERCOT shall estimate the projected total generation requirement by calculating a Load forecast for the study period. In lieu of the steps described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the non-binding projection of Real-Time Reliability Deployment Price Adders shall be estimated based on GTBD, reliability deployments MWs, and aggregated offers. The Energy Offer Curve from SCED Step 2, the virtual offers for Load Resources deployed and the power balance penalty curve will be compared against the updated GTBD to get an estimate of the System Lambda from paragraph (2)(m) of Section 6.5.7.3.1. ERCOT shall post the projected non-binding Base Points for each Resource for each interval study period on the MIS Certified Area and the projected non-binding LMPs for Resource Nodes, Real-Time Reliability Deployment Price Adders, Real-Time On-Line Reserve Price Adders, Real-Time Off-Line Reserve Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.

(12) For each SCED process, ERCOT shall calculate a Real-Time On-Line Reserve Price Adder and a Real-Time Off-Line Reserve Price Adder based on the On-Line and Off-Line available reserves in the ERCOT System and the Operating Reserve Demand Curve (ORDC). The Real-Time Off-Line available reserves shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is equal to or below the PRC MW at which Energy Emergency Alert (EEA) Level 1 is initiated. In addition, for each SCED process, ERCOT shall calculate a Real-Time On-Line Reliability Deployment Price Adder. The sum of the Real-Time Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder shall be averaged over the 15-minute Settlement Interval and added to the Real-Time LMPs to determine the Real-Time Settlement Point Prices. The price after the addition of the sum of the Real-Time On-Line Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder to LMPs approximates the pricing outcome of the impact to energy prices from reliability deployments and the Real-Time energy and Ancillary Service co-optimization since the Real-Time On-Line Reserve Price Adder captures the value of the opportunity cost of reserves based on the defined ORDC. An Ancillary Service imbalance Settlement

shall be performed pursuant to Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, to make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves.

(13) ERCOT shall determine the methodology for implementing the ORDC to calculate the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder. Following review by TAC, the ERCOT Board shall review the recommendation and approve a final methodology. Within two Business Days following approval by the ERCOT Board, ERCOT shall post the methodology on the ERCOT website.

(14) At the end of each season, ERCOT shall determine the ORDC for the same season in the upcoming year, based on historic data using the ERCOT Board-approved methodology for implementing the ORDC. Annually, ERCOT shall verify that the ORDC is adequately representative of the loss of Load probability for varying levels of reserves. Twenty days after the end of the Season, ERCOT shall post the ORDC for the same season of the upcoming year on the ERCOT website.

(15) ERCOT may override one or more of a Controllable Load Resource's parameters in SCED if ERCOT determines that the Controllable Load Resource's participation is having an adverse impact on the reliability of the ERCOT System.

(16) The QSE representing an ESR, in order to charge the ESR, must submit RTM Energy Bids, and the ESR may withdraw energy from the ERCOT System only when dispatched by SCED to do so. An ESR may telemeter a status of OUTL only if the ESR is in Outage status.

6.5.7.6.2.4 Deployment and Recall of ERCOT Contingency Reserve Service

(1) ECRS is intended to:

(a) Help restore the frequency to 60 Hz within ten minutes of a significant frequency deviation;

(b) Provide energy to avoid, or during the implementation of, an EEA;

(c) Provide backup to Reg-Up; and

(d) Provide energy upon detection of insufficient available capacity for net load ramps.

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

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

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

(3) ERCOT shall release ECRS from Generation Resources and Controllable Load Resources to SCED when frequency drops below 59.91 Hz and available Reg-Up is not sufficient to restore frequency. Upon deployment of Off-Line ECRS from a QSGR providing ECRS, the Resource's Ancillary Service Schedule for ECRS must be adjusted for the ERCOT instructed ECRS deployment and the Resource's status must be set to OFFQS to be available for dispatch by SCED. Once recalled QSGRs providing ECRS must follow the decommitment process outlined in Section 3.8.3.1, Quick Start Generation Resource Decommitment Decision Process.

(4) Energy from Resources providing ECRS may also be manually deployed by ERCOT pursuant to Section 6.5.9, Emergency Operations.

(5) ERCOT may manually release up to 500 MW of ECRS capacity from SCED-dispatchable Resources when the power balance constraint is violated and the MW amount of power balance constraint violation is at or above ~~30~~40 MW for at least ten consecutive minutes. Following such an ECRS release, if the power balance constraint violation remains at or above ~~30~~40 MW, ERCOT may release additional MW of ECRS from SCED-dispatchable Resources ~~but will reserve at least 900 MW of SCED-dispatchable ECRS~~. When manually releasing SCED-dispatchable ECRS, ERCOT may preserve some SCED-dispatchable ECRS to ensure that ERCOT has sufficient capacity that can respond and help recover frequency within the parameters required by NERC Reliability Standards. However, if the power balance constraint violation remains at or above 40 MW, ERCOT will continue to release ECRS in small blocks.

(6~~5~~) ERCOT shall use SCED and Non-Spin as soon as practicable to recover ECRS reserves.

(7~~6~~) Following an ECRS deployment to SCED-dispatchable Resources, the QSE's obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction or its ECRS obligation expires, whichever occurs first. Following an ECRS deployment to Load Resources, excluding Controllable Load Resources, or Resources operating in synchronous condenser fast-response mode, the QSE's obligation to deliver ECRS remains in effect until ERCOT issues a recall instruction.

(8~~7~~) Following a deployment or recall Dispatch Instruction of ECRS, a QSE shall adjust the telemetered ECRS Ancillary Service Schedule for the Resource providing the service and ERCOT shall adjust the HASL based on the QSE's telemetered Ancillary Service Schedule for ECRS, as described in Section 6.5.7.2, Resource Limit Calculator, to account for such deployment.

(9~~8~~) For Generation Resources and Controllable Load Resources providing ECRS, Base Points include ECRS energy as well as any other energy dispatched by SCED. A Resource must be able to be fully dispatched by SCED to its ECRS Ancillary Service Resource Responsibility within the ten-minute time frame according to its telemetered Emergency Ramp Rate.

(10~~9~~) Each QSE providing ECRS shall meet the deployment performance requirements specified in Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria.

(11~~0~~) ERCOT shall issue instructions to release ECRS capacity provided from Generation Resources and Controllable Load Resources to SCED over ICCP and shall issue deployment instructions for Load Resources providing ECRS via XML. Such instructions shall contain the MW requested.

(12~~1~~) To the extent that ERCOT deploys a Load Resource that is not a Controllable Load Resource and that has chosen a block deployment option, ERCOT shall either deploy the entire Ancillary Service Resource Responsibility or, if only partial deployment is possible, skip the Load Resource with the block deployment option and proceed to deploy the next available Resource.

(13~~2~~) ERCOT shall recall automatically deployed ECRS capacity once system frequency recovers above 59.97 Hz.

(14~~3~~) ERCOT shall recall ECRS deployment provided from a Load Resource that is not a Controllable Load Resource once PRC is above a pre-defined threshold, as described in the Operating Guides.

(15) ERCOT may~~shall~~ recall manually released ECRS capacity from SCED-dispatchable Resources when the triggering condition in paragraph (5) has ended and the ERCOT System is operating with a steady-state frequency above 59.97 Hz.

[NPRR1010: Replace Section 6.5.7.6.2.4 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

6.5.7.6.2.4 Deployment and Recall of ERCOT Contingency Reserve Service

(1) ECRS is intended to:

(a) Help restore the frequency to 60 Hz within ten minutes of a significant frequency deviation;

(b) Provide energy to avoid, or during the implementation of, an EEA;

(c) Provide backup to Reg-Up; and

(d) Provide energy upon detection of insufficient available capacity for net load ramps.

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