Filing Receipt

Filed Date - 2025-06-26 12:57:43 PM

Control Number - 54445

Item Number - 112

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 23-24, 2025, the ERCOT Board of Directors (Board) recommended Commission approval of the following proposed revisions to the ERCOT rules (Revision Requests), Nodal Operating Guide Revision Requests (NOGRRs), (Nodal Protocol Revision Requests (NPRRs), Other Binding Documents Revision Request (OBDRR), Planning Guide Revision Request (PGRR), and System Change Request (SCR):

- NOGRR265, Related to NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities
- NOGRR275, Eliminate Scheduling Center Requirements for QSEs That Are Not WAN Participants
- NOGRR277, Related to NPRR1282, Ancillary Service Duration under Real-Time Co-Optimization
- NPRR1226, Estimated Demand Response Data
- NPRR1229, Real-Time Constraint Management Plan Cost Recovery Payment
- NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities
- NPRR1267, Large Load Interconnection Status Report
- NPRR1271, Revision to User Security Administrator and Digital Certificates Opt-out Eligibility
- NPRR1276, Move OBD to Section 22 – Emergency Response Service Procurement Methodology
- NPRR1282, Ancillary Service Duration under Real-Time Co-Optimization
- OBDRR054, TDSP(s) Pre-Production Verification Testing

- PGRR125, Update of Lone Star Infrastructure Protection Act (LSIPA) Compliance Attestation
- SCR830, Expose Limited API Endpoints Using Machine-to-Machine Authentication

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 26, 2025

Respectfully submitted,

/s/ Brandt Rydell

Chad V. Seely
SVP Regulatory Policy, General Counsel,
and Chief Compliance Officer
Texas Bar No. 24037466
(512) 225-7035 (Phone)
chad.seely@ercot.com

Brandt Rydell
Deputy General Counsel
Texas Bar No. 00798477
(512) 248-3928 (Phone)
brandt.rydell@ercot.com

ERCOT
8000 Metropolis Drive (Building E), Suite 100
Austin, Texas 78744
(512) 225-7079 (Fax)

ATTORNEYS FOR ELECTRIC RELIABILITY
COUNCIL OF TEXAS, INC.

Board Report

NOGRR Number	**265**	**NOGRR Title**	**Related to NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities**

Date of Decision	June 24, 2025
Action	Recommended Approval
Timeline	Normal
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required
Proposed Effective Date	Upon system implementation of Nodal Protocol Revision Request (NPRR) 1238, Voluntary Registration of Loads with Curtailable Load Capabilities
Priority and Rank Assigned	Not applicable
Nodal Operating Guide Sections Requiring Revision	4.5.3.1, General Procedures Prior to EEA Operations 4.5.3.4, Qualified Scheduling Entity VECL Load Shed Obligation (new) 4.5.3.4, Load Shed Obligation
Related Documents Requiring Revision/Related Revision Requests	NPRR1238
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) establishes a process by which Loads may operate as a Voluntary Early Curtailment Load (VECL) so that they can be accounted for differently in Load shed tables than other Loads.
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

Board Report

	☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NOGRR establishes a process by which Loads may inform ERCOT that the Load consumer is willing to curtail in the event of a Physical Responsive Capability (PRC) shortfall as defined in Section 4.5.3.1 in order to help utilities and ERCOT properly account for Load shed obligations. This process is necessary so that utilities with large Loads that will be Off-Line during emergency operations don't impact that utility's expected Load shed obligations. For example, a utility that typically has 200 MW of Demand may have a new customer that is adding 800 MW of Demand. If they are expected to shed 5% of their Load during an emergency, then the Load shed obligation would increase from 10 MW to 50 MW. If the new 800 MW customer will actually be Off-Line, then it should have no incremental impact on the utility's Load shed obligation.
ROS Decision	On 7/11/24, ROS voted unanimously to table NOGRR265 and refer the issue to Operations Working Group (OWG). All Market Segments participated in the vote. On 3/6/25, ROS voted unanimously to recommend approval of NOGRR265 as amended by the 2/6/25 ERCOT comments. All Market Segments participated in the vote. On 5/1/25, ROS voted unanimously to table NOGRR265. All Market Segments participated in the vote. On 5/20/25, ROS voted unanimously via email to endorse and forward to TAC the 5/1/25 ROS Report as amended by the 5/7/25 ERCOT comments and the 5/13/25 Impact Analysis for NOGRR265. All Market Segments participated in the email vote.
Summary of ROS Discussion	On 7/11/24, the sponsor provided an overview of NOGRR265, confirmed that there was no longer a need for urgency, and requested that NOGRR265 be referred to OWG. Participants referenced comments expected from multiple parties. On 3/6/25, ROS reviewed the 2/6/25 ERCOT comments. ERCOT Staff clarified that NOGRR265 removes Early Curtailment Load (ECL) from all Load Ratio Share (LRS) calculations.

	On 5/1/25, ROS reviewed the 4/29/25 ERCOT comments. Participants acknowledged previous failure to take required voting action on NOGRR265 at the April 3, 2025 ROS meeting. On 5/20/25, there was no discussion.
TAC Decision	On 5/28/25, TAC voted unanimously to table NOGRR265. All Market Segments participated in the vote. On 6/12/25, TAC voted unanimously to recommend approval of NOGRR265 as recommended by ROS in the 5/20/25 ROS Report as amended by the 6/5/25 TIEC comments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/28/25, there was no additional discussion beyond TAC review of NPRR1238 and the items below. On 6/12/25, TAC reviewed the 6/5/25 TIEC comments, 6/10/25 GSEC comments, and the 6/11/25 ERCOT comments.
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 6/24/25, the ERCOT Board voted unanimously to recommend approval of NOGRR265 as recommended by TAC in the 6/12/25 TAC Report and the 6/13/25 Revised Impact Analysis.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR265.
ERCOT Opinion	ERCOT supports approval of NOGRR265.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR265 and believes that it provides improvements by introducing a new category of VECL and establishing a process by which Loads may operate as a VECL so

	that they can be accounted for differently in Load shed tables than other Loads.

Sponsor	
Name	Joe Dan Wilson
E-mail Address	jwilson@gsec.coop
Company	Golden Spread Electric Cooperative (GSEC)
Phone Number	806-349-5210
Cell Number	806-340-1214
Market Segment	Cooperative

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**
ERCOT 071024	Requested ROS table NOGRR265 to provide additional time to provide comments
Oncor 081424	Provided additional edits regarding the role of Transmission Operators (TOs) and clarified TOs' expected needs in the event ERCOT instructs disconnection of a VECL
ERCOT 020625	Provided additional clarifying edits
ERCOT 033125	Proposed an alternative schedule to complete the Impact Analysis for NOGRR265 prior to the May 1, 2025 ROS meeting
ERCOT 042925	Proposed an alternative schedule to complete the Impact Analysis for NOGRR265 prior to the June 5, 2025 ROS meeting
ERCOT 050725	Proposed edits to remove language requiring ERCOT to notify TOs of the ECL deployment via an Extensible Markup Language (XML) message in alignment with similar edits proposed to NPRR1238

ERCOT 052725	Requested that TAC table NOGRR265 until Senate Bill (SB6) language has been finalized
TIEC 060525	Proposed edits clarifying that the registration of loads with curtailable load capabilities must be voluntary
GSEC 061025	Expressed support for the 6/5/25 TIEC comments
ERCOT 061125	Expressed support for NOGRR265 upon identifying anticipated use cases not appearing to raise a risk of conflict with the requirements of SB6; emphasized, in response to the 6/5/25 TIEC comments, that, while registration as an ECL (or VECL) may be voluntary, the performance requirements under the Protocols for customers that do elect such registration would not be voluntary

Market Rules Notes

Please note the baseline Nodal Operating Guide language in the following Section(s) has been updated to reflect the incorporation of the following NOGRR(s) into the Nodal Operating Guide:

- NOGRR262, Provisions for Operator-Controlled Manual Load Shed (incorporated 12/1/24)
    - Section 4.5.3.4
- NOGRR274, Conform Nodal Operating Guide to Revisions Implemented for NPRR1217, Remove Verbal Dispatch Instruction (VDI) Requirement for Deployment and Recall of Load Resources and Emergency Response Service (ERS) Resources (incorporated 6/1/25)
    - Section 4.5.3.1

Proposed Guide Language Revision

4.5.3.1 General Procedures Prior to EEA Operations

(1) Prior to declaring EEA Level 1 detailed in Section 4.5.3.3, EEA Levels, ERCOT may perform the following operations consistent with Good Utility Practice:

(a) Provide Dispatch Instructions to QSEs for specific Resources to operate at an Emergency Base Point to maximize Resource deployment so as to increase Responsive Reserve (RRS) levels on other Resources;

(b) Commit specific available Resources as necessary that can respond in the timeframe of the emergency. Such commitments will be settled using the Hourly Reliability Unit Commitment (HRUC) process;

(c) Start Reliability Must-Run (RMR) Units available in the time frame of the emergency. RMR Units should be loaded to full capability;

(d) Utilize available Resources providing RRS, ERCOT Contingency Reserve Service (ECRS), and Non-Spinning Reserve (Non-Spin) services as required;

(e) Instruct TSPs and Distribution Service Providers (DSPs) or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures if ERCOT determines that the implementation of these measures could help avoid entering into EEA and ERCOT does not expect to need to use these measures to reduce the amount of Load shedding that may be needed in EEA Level 3. A TSP, DSP, or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability; and

(f) ERCOT shall use the PRC and system frequency to determine the appropriate Emergency Notice and EEA levels.

~~(2) A Load that is willing to curtail during any shortfall described in this Section, subject to an agreement with its QSE, interconnecting TO, and interconnecting Transmission and/or Distribution Service Provider(s) (TDSP(s)), shall be registered by the QSE as a Voluntary Early Curtailment Load (VECL) pursuant to Protocol Section 16.20, Designation of a Qualified Scheduling Entity by a Voluntary Early Curtailment Load.~~

(2~~3~~) When PRC falls below 3,100 MW and is not projected to be recovered above 3,100 MW within 30 minutes following the deployment of Non-Spin, ERCOT may deploy some or all Voluntary Early Curtailment Loads (~~V~~VECLs) via an Extensible Markup Language (XML) message~~in 100 MW blocks allocated to QSEs~~, as described in Section 4.5.3.4, Qualified Scheduling Entity ~~V~~VECL Load Reduction~~Shed~~ Obligation, in order to maintain or restore 3,100 MW of PRC to the greatest extent possible.

(a) ~~V~~VECLs may be deployed ~~in any number of 100 MW blocks~~ and at any time in a Settlement Interval at the discretion of ERCOT operators.

(b) Upon deployment of any amount of ~~V~~VECLs, ERCOT shall notify all Market Participants via an operations message that such deployment has been made and shall specify the MW capacity of ~~V~~VECL deployed.

(c) ERCOT shall notify QSEs ~~and TOs~~ of the ~~V~~VECLs deployment via an ~~Extensible Markup (~~XML~~)~~ message. The deployment time within the ERCOT XML deployment message shall initiate the ~~V~~VECL deployment and the ~~V~~VECL ramp period.

(d) Upon receipt of a~~n~~ VECL deployment, QSEs shall instruct their ~~V~~VECLs to reduce~~cease~~ consumption without delay in a time period not to exceed ~~within~~ 30 minutes from the start of the ~~V~~VECL ramp period, and the deployed ~~V~~VECLs shall comply with those instructions. ~~When responding to this deployment instruction, the VECL shall limit their ramp rate to 20% per minute.~~

(e) ~~QSEs shall promptly notify the ERCOT operator of any VECLs that are unable to comply with a deployment instruction, including the reason for the failure to comply.~~ If a~~n~~ VECL fails to comply with a deployment instruction, ERCOT may instruct the applicable TO~~TSP~~ ~~or QSE (if the VECL is behind the Point of Interconnection (POI) of a generator)~~ to remotely disconnect ~~a~~the ~~V~~VECL. If a~~n~~ VECL that fails to comply with a deployment instruction is co-located with an ERCOT Resource, ERCOT may instruct the Customer's QSE to remotely disconnect the VECL, in which case the QSE shall ensure that the VECL is promptly disconnected from the ERCOT System~~ that fails to comply with a deployment instruction~~.

(f) ERCOT shall notify QSEs of the termination of the ~~V~~VECLs deployment via an XML recall message. The ERCOT XML recall message shall represent the official notice of the ~~V~~VECLs recall.

(i) If ERCOT has instructed the interconnecting TO to disconnect a~~n~~ ~~V~~VECL for failure to comply with a deployment instruction, ERCOT will also notify the TO once the ~~V~~VECL deployment has been terminated, so that the ~~V~~VECL can be reconnected.

(g) Upon termination of the ~~V~~VECLs deployment, any ~~V~~VECL shall not increase consumption at a rate exceeding 20% per minute.

(h) Upon termination of ~~V~~VECLs deployment, ERCOT shall notify all Market Participants via an operations message that such deployment has been terminated and shall specify the MW capacity of ~~V~~VECLs recalled.

(43) When PRC falls below 3,000 MW and is not projected to be recovered above 3,000 MW within 30 minutes following the deployment of Non-Spin and all VECL, ERCOT may deploy available contracted Emergency Response Service (ERS)-10 and ERS-30 via an ~~Extensible Markup Language (~~XML~~)~~ message. The deployment time within the ERCOT XML deployment message shall represent the beginning of the ERS-10 and ERS-30 ramp periods.

(a) ERS-10 and ERS-30 may be deployed at any time in a Settlement Interval. ERS-10 and ERS-30 may be deployed either simultaneously or separately, and in any order, at the discretion of ERCOT operators.

(b) Upon deployment, QSEs shall instruct their ERS Resources in ERS-10 and ERS-30 to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources, until either ERCOT recalls the ERS-10 and ERS-30 deployment or the ERS-10 and ERS-30 Resources have reached their maximum deployment time.

(c) ERCOT shall notify QSEs of the recall of ERS-10 and ERS-30 via an XML message. The recall time within the ERCOT XML message shall represent the official notice of ERS-10 and ERS-30 recall.

(d) Upon recall, an ERS Resource shall return to a condition such that it is capable of meeting its ERS performance requirements as soon as practical, but no later than ten hours following the recall.

(3~~5~~4) When a Watch is issued for PRC below 3,000 MW and ERCOT expects system conditions to deteriorate to the extent that an EEA Level 2 or 3 may be experienced, ERCOT shall evaluate constraints active in SCED and determine which constraints have the potential to limit generation output.

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

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

(a) Upon identification of such constraints, ERCOT shall coordinate with the TSPs and DCTOs that own or operate the overloaded Transmission Facilities associated with those constraints, as well as the Resource Entities whose generation output may be limited, to determine whether:

(i) A 15-Minute Rating is available that allows for additional transmission capacity for use in congestion management, if an EEA Level 2 or 3 is declared, and post-contingency actions can be taken within 15 minutes to return the flow to within the Emergency Rating. Such actions may include, but are not limited to, reducing the generation that increased output as a result of enforcing the 15-Minute Rating rather than the Emergency Rating;

(ii) Post-contingency loading of the Transmission Facilities is expected to be at or below Normal Rating within two hours; or

(iii) Additional transmission capacity could allow for additional output from a limited Generation Resource by taking one of the following actions:

(A) Restoring Transmission Elements that are out of service;

(B) Reconfiguring the transmission system; or

(C) Making adjustments to phase angle regulator tap positions.

If ERCOT determines that one of the above-mentioned actions allows for additional output from a limited Generation Resource, ERCOT may instruct the TSPs to take the action(s) during the Advisory to allow for additional output from the limited Generation Resource.

(b) ERCOT shall also coordinate with TSPs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.

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

(b) ERCOT shall also coordinate with TSPs and DCTOs who own and operate the Transmission Facilities associated with the double-circuit contingencies for the constraints identified above to determine whether the double-circuit failures are at a high risk of occurring due to system conditions, which may include: severe weather conditions forecasted by ERCOT in the vicinity of the double-circuit, weather conditions that indicate a high risk of insulator flashover on the double-circuit, repeated Forced Outages of the individual circuits that are part of the double-circuit in the preceding 48 hours, or fire in progress in the right of way of the double-circuit.

(c) The actions detailed in this Section shall be supplemental to the development and maintenance of Constraint Management Plans (CMPs) as otherwise directed by the Protocols or Operating Guides.

(4~~6~~5) When a Watch is issued for PRC below 3,000 MW, QSEs shall suspend any ongoing ERCOT-required Resource performance testing.

4.5.3.4 Qualified Scheduling Entity ~~V~~VECL Load Reduction~~Shed~~ Obligation

(1) Each QSE representing one or more ~~V~~VECLs shall take and direct actions to ensure that ERCOT ~~V~~VECL ~~Load shed~~deployment instructions are effectuated. Each ~~V~~VECL shall comply with any reasonable instruction given by its QSE to effectuate Load reduction~~shed~~ obligations.

~~(2) ERCOT shall update the QSE VECL Load-shedding allocation percentage table twice each year in coordination with the summer and winter TO Load Shed Obligation determinations calendar quarter. The allocation percentages may be revised as otherwise appropriate to reflect any new or changed QSE designation~~

~~and VECL amount as reflected in the Resource Integration and Ongoing Operations ("RIOO") system. ERCOT shall maintain and post on the ERCOT website a QSE VECL Load shed table that reflects each QSE's total VECL Load shed obligation.~~

~~(3) Following ERCOT's quarterly VECL review or ERCOT's receipt of any new or changed QSE designation, ERCOT shall post any anticipated revisions to the QSE VECL Load shed table on the ERCOT website. ERCOT shall issue a Market Notice announcing the posting of the revisions at least ten days prior to the effective date of the revisions or as soon as practicable if ERCOT determines there is a need to correct the Market Notice less than ten days before the effective date.~~

4.5.3.45 Transmission Operator Load Shed Obligation

(1) Each TO shall take and direct actions to ensure that ERCOT Load shed instructions are effectuated. Each DSP shall comply with any reasonable instruction given by its TO to effectuate Load shed obligations.

(2) Load shed obligation percentages for ERCOT EEA Level 3 Load shedding will be determined by calculating each TO's Load as a percentage of the ERCOT System summer and winter peak 15 minute Demand interval. For the purposes of this paragraph, TO Load, with the exception of ~~V~~VECLs, will be the amount of Load being served by all of the Transmission and/or Distribution Service Providers (TDSPs) that the TO represents. The calculations for summer and winter Load shed obligation percentage are as follows:

(a) The calculated Load shed obligation percentage for the summer Season will be based on the single highest coincident ERCOT System peak 15 minute Demand interval for the summer months of June through September as reflected in the 4-Coincident Peak (4-CP) data submitted by ERCOT to the Public Utility Commission of Texas (PUCT) for that year. Anticipated revisions to the summer Load shed table shall be posted as described in paragraph (4) below no later than March 31st of each year based on data from the previous calendar year.

(b) The calculated Load shed obligation percentage for the winter Season will be based on the single highest coincident ERCOT System peak 15 minute Demand interval for the winter months of December through February as reflected at the time that ERCOT extracts the Load data for the winter Season from its settlement system. Anticipated revisions to the winter Load shed table shall be posted as described in paragraph (4) below no later than August 31st of each year based on data from December of the previous calendar year and January through February of the current year.

(3) The summer Load shed table will be used during a hot weather Load shed event and the winter Load shed table will be used during a cold weather Load shed event. ERCOT will determine, in its sole discretion, whether an EEA event will be treated as a hot weather or cold weather Load shed event based on the weather conditions. The summer and winter Load shed time periods will be published annually with the updated obligation tables in

paragraph (2) above. In addition, if ERCOT issues an Operating Condition Notice (OCN), it will notify Market Participants which Load shed table would apply to the potential Load shed event. When ERCOT directs TOs to shed Load, it will specify which Load shed table applies for the Load shed event. ERCOT shall use the same Load shed table for the duration of a Load shed event.

(4) ERCOT shall maintain the Seasonal Load shed tables reflecting each TO's total Load shed obligation on the ERCOT website. The Load shed obligation percentages will be reviewed by ERCOT and revised as described above, or as otherwise deemed appropriate by ERCOT, to reflect any new or changed TO designation by a DSP or changes in the VECL registration. Adjustments to the Load shed obligations due to changes in TO designations will be performed using the same Load data upon which the table was based. Following ERCOT's Seasonal peak Load reviews or ERCOT's receipt of any new or changed TO designation, ERCOT shall post any anticipated revisions to the Load shed tables on the ERCOT website. ERCOT shall issue a Market Notice announcing the posting of the revisions at least ten days prior to the effective date of the revisions or as soon as practicable if ERCOT determines there is a need to correct the Market Notice less than ten days before the effective date.

(5) Each TO shall coordinate with each TDSP it represents to:

(a) Minimize overlap of circuits that are designated for manual firm Load shed with circuits that serve designated critical loads; and

(b) Minimize overlap of circuits that are designated for manual firm Load shed with circuits that are utilized for UFLS and Under-Voltage Load Shed (UVLS).

Revised ERCOT Impact Analysis Report

NOGRR Number	265	NOGRR Title	Related to NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities
Impact Analysis Date	June 13, 2025		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1238, Voluntary Registration of Loads with Curtailable Load Capabilities.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1238.

Board Report

NOGRR Number	275	NOGRR Title	Eliminate Scheduling Center Requirements for QSEs That Are Not WAN Participants
Date of Decision	June 24, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	3.2.1, Operating Obligations		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns the Nodal Operating Guide with the Protocols to eliminate scheduling center requirements for Qualified Scheduling Entities (QSEs) that are not Wide Area Network (WAN) Participants.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s)		

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	This NOGRR is required to align the Nodal Operating Guide with changes in the Protocols made by Nodal Protocol Revision Request (NPRR) 1206, Revisions to QSE Operations and Termination Requirements, and Elimination of Providing Certain Market Participant Principal Information, related to requirements for control or operations centers.
ROS Decision	On 4/3/25, ROS voted unanimously to recommend approval of NOGRR275 as revised by ROS. All Market Segments participated in the vote. On 5/1/25, ROS voted unanimously to endorse and forward to TAC the 4/3/25 ROS Report and 2/28/25 Impact Analysis for NOGRR275. All Market Segments participated in the vote.
Summary of ROS Discussion	On 4/3/25, ROS reviewed NOGRR275. Participants proposed a clarification desktop edit which ERCOT endorsed. On 5/1/25, ROS reviewed the 2/28/25 Impact Analysis.
TAC Decision	On 5/28/25, TAC voted unanimously to recommend approval of NOGRR275 as recommended by ROS in the 5/1/25 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/28/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)

Board Report

ERCOT Board Decision	On 6/24/25, the ERCOT Board voted unanimously to recommend approval of NOGRR275 as recommended by TAC in the 5/28/25 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR275.
ERCOT Opinion	ERCOT supports approval of NOGRR275.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR275 and believes that it provides process improvements by aligning the Nodal Operating Guide with the Protocols to eliminate scheduling center requirements for QSEs that are not WAN Participants.

Sponsor	
Name	Katherine Gross / Ted Hailu
E-mail Address	Katherine.Gross@ercot.com / Ted.Hailu@ercot.com
Company	ERCOT
Phone Number	512-225-7184 / 512-248-3873
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

Board Report

None

Proposed Guide Language Revision

3.2.1 Operating Obligations

(1) ~~A~~ Qualified Scheduling ~~Entity~~ Entities (QSEs) that are Wide Area Network (WAN) Participants shall maintain a control or operations~~scheduling~~ center with qualified personnel with the authority to commit and bind the QSE, as described in Protocol Section 16.2, Registration and Qualification of Qualified Scheduling Entities. QSEs shall communicate with ERCOT for the purpose of meeting their obligations specified in the Protocols and these Operating Guides. Each QSE shall designate an Authorized Representative as defined in Protocol Section 2.1, Definitions.

(2) ~~Each~~ QSEs that are WAN Participants shall submit to ERCOT, by March 15 of each year, a written back-up control plan to continue operation of the control or operations center in the event the QSE's control or operations~~scheduling~~ center becomes inoperable. Back-up control plans shall be submitted to ERCOT via secured webmail or encrypted data transfer. QSEs shall request that a secure email account be created with ERCOT by sending an email to shiftsupervisors@ercot.com.

(3) Each back-up control plan shall be reviewed and updated annually and shall include as a minimum, the following:

(a) Description of actions to be taken by QSE personnel to avoid placing a prolonged burden on ERCOT and other Market Participants, while operating in back-up control mode;

(b) Description of specific functions and responsibilities to be performed to continue operations from an alternate location;

(c) Procedures and responsibilities for maintaining basic voice communications capabilities with ERCOT; and

(d) Procedures for back-up control function testing and the training of personnel.

(4) As an option, the back-up control plan may include arrangements made with another Entity to provide the minimum back-up control functions in the event the QSE's primary functions are interrupted.

(5) For connectivity requirements for back-up sites, refer to Section 7, Telemetry and Communication.

ERCOT Impact Analysis Report

NOGRR Number	**275**	**NOGRR Title**	**Eliminate Scheduling Center Requirements for QSEs That Are Not WAN Participants**
Impact Analysis Date	February 28, 2025		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Glossary Revision Request (NOGRR) 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

NOGRR Number	277	NOGRR Title	Related to NPRR1282, Ancillary Service Duration under Real-Time Co-Optimization
Date of Decision	June 24, 2025		
Action	Recommended Approval		
Timeline	Urgent - to allow for ERCOT Board consideration in June 2025 and Public Utility Commission of Texas (PUCT) consideration in July 2025, so the open-loop testing in July 2025 and subsequent phases incorporates this change.		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon system implementation of Nodal Protocol Revision Request (NPRR) 1282, Ancillary Service Duration under Real-Time Co-Optimization		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	2.3, Ancillary Services 2.3.3.1, Additional Operational Details for ERCOT Contingency Reserve Service (ECRS) Providers		
Related Documents Requiring Revision/Related Revision Requests	NPRR1282		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) updates duration requirements for ERCOT Contingency Reserve Service (ECRS) to one hour.		
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	This NOGRR proposes changes to the Nodal Operating Guides to align with changes proposed in NPRR1282. As described further in NPRR1282, ERCOT conducted an analysis in anticipation of the upcoming implementation of the Real-Time Co-Optimization plus Batteries (RTC+B) project and recommends that the required duration of ECRS be changed from two hours to one hour.
ROS Decision	On 5/20/25, ROS voted via email to grant NOGRR277 Urgent status; to recommend approval of NOGRR277 as submitted; and to forward to TAC NOGRR277 and the 4/29/25 Impact Analysis. There was one opposing vote from the Independent Generator (Southern Power) Market Segment and one abstention from the Consumer (OPUC) Market Segment. All Market Segments participated in the vote.
Summary of ROS Discussion	On 5/20/25, there was no discussion.
TAC Decision	On 5/28/25, TAC voted to recommend approval NOGRR277 as recommended by ROS in the 5/20/25 ROS Report. There were two abstentions from the Independent Generator (Engie, Jupiter Power) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/28/25, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 6/24/25, the ERCOT Board voted unanimously to recommend approval of NOGRR277 as recommended by TAC in the 5/28/25 TAC Report.

Board Report

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR277.
ERCOT Opinion	ERCOT supports approval of NOGRR277.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR277 and believes the market impact for NOGRR277, along with NPRR1282, provides reasonable, study-based duration requirements for ECRS in preparation for RTC+B go-live, and ERCOT agrees that this duration parameter can be revisited after go-live when there is history with the RTC+B systems implemented and observations regarding market and reliability outcomes.

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**
None	

Market Rules Notes

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

Board Report

- NPRR264, Related to NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  - Section 2.3

Proposed Guide Language Revision

2.3 Ancillary Services

Commented [CP1]: Please note NOGRR264 also proposes revisions to this section.

(1) The types of Ancillary Services required by ERCOT are described below:

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Regulation Down Service (Reg-Down) and Regulation Up Service (Reg-Up) (for Generation Resources and Energy Storage Resources (ESRs)) ***Reference: Protocol Section 2, Definitions and Acronyms***	Resource capacity provided by a Qualified Scheduling Entity (QSE) from a specific Generation Resource or ESR to control frequency within the system which is controlled second by second, normally by an Automatic Generation Control (AGC) system.	a. Reg-Down energy is a deployment to increase or decrease generation at a level below the Generation Resource's or ESR's Base Point in response to a change in system frequency. b. Reg-Up energy is a deployment to increase or decrease generation at a level above the Generation Resource's or ESR's Base Point in response to a change in system frequency.
Reg-Down and Reg-Up (for Load Resource) ***Reference: Protocol Section 2***	Load Resource capacity provided by a QSE from a specific Load Resource to control frequency within the system.	a. Reg-Down is a deployment to increase or decrease Load as deployed within its Ancillary Service Schedule for Reg-Down below the Load Resource's Maximum Power Consumption (MPC) limit in response to a change in system frequency. b. Reg-Up is a deployment to increase or decrease Load as deployed within its Ancillary Service Schedule for Reg-Up above the Load Resource's Low Power Consumption

Board Report

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
		(LPC) limit in response to a change in system frequency.
Responsive Reserve (RRS) ***Reference: Protocol Section 2***	Operating reserves on Generation Resources, ESRs, Load Resources, and Resources capable of providing Fast Frequency Response (FFR) maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources, ESRs, and Controllable Load can be used as energy during an Energy Emergency Alert (EEA) event.	RRS may only be deployed as follows: a. Through automatic Governor action or under-frequency relay in response to frequency deviations; b. By electronic signal from ERCOT in response to the need; and c. As ordered by an ERCOT Operator during an EEA or other emergencies.
ERCOT Contingency Reserve Service (ECRS) ***Reference: Protocol Section 2***	a. Off-Line Generation Resource capacity, or reserved capacity from On-Line Generation Resources, capable of being ramped to a specified output level within ten minutes, operating at a specified output for at least two consecutive hours, and are dispatchable by Security-Constrained Economic Dispatch (SCED). b. Controllable Load Resources dispatchable by SCED that are capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
	ERCOT-instructed level for at least two consecutive hours. c. Load Resources that are not Controllable Load Resources and may or may not be controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing ECRS must be capable of reducing Load in response to an Extensible Markup Language (XML) Dispatch Instruction within ten minutes and remain deployed until recalled by ERCOT.	
Non-Spinning Reserve (Non-Spin) Service ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within 30 minutes and operating at a specified output for at least four consecutive hours. b. Controllable Load Resources that are capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for at least four consecutive hours. c. Load Resources that are not Controllable Load Resources and that are not controlled by under-frequency relay. Load Resources that are not Controllable Load Resources	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
	providing Non-Spin must be capable of reducing Load in response to an XML Dispatch Instruction within 30 minutes and remain deployed until recalled by ERCOT.	
Voltage Support Service (VSS) ***Reference: Protocol Section 3.15, Voltage Support***	Reactive capability of a Generation Resource or ESR that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits. All Generation Resources and ESRs with a gross rating greater than 20 MVA shall provide VSS.	Direct the scheduling of VSS by providing Voltage Profiles at the Point of Interconnection Bus (POIB). The Generation Resource or ESR is obligated to maintain the published Voltage Profile within its Corrected Unit Reactive Limit ("CURL").
Black Start Service (BSS) ***Reference: Protocol Section*** 3.14.2, ***Black Start***	The provision of Generation Resources under a Black Start Agreement, which are capable of self-starting without support from within ERCOT in the event of a Partial Blackout or Blackout.	Provide emergency Dispatch Instructions to begin restoration to a secure operating state after a Partial Blackout or Blackout.
Reliability Must-Run (RMR) Service ***Reference: Protocol Section*** 3.14.1, ***Reliability Must Run***	The provision of Generation Resource capacity and energy under an RMR Agreement.	Enter into contractual agreements to retain units required for reliable operations. Direct the operation of those units that otherwise would not operate and that are necessary to provide reliable operations.

Board Report

[NOGRR211: Replace paragraph (1) above with the following upon system implementation of NPRR1007:]

(1) The types of Ancillary Services required by ERCOT are described below:

ANCILLARY SERVICE TYPE	DESCRIPTION	ERCOT AUTHORITY ACTION
Regulation Down Service (Reg-Down) and Regulation Up Service (Reg-Up) (for Generation Resources and Energy Storage Resources (ESRs)) ***Reference: Protocol Section 2, Definitions and Acronyms***	Resource capacity provided by a Qualified Scheduling Entity (QSE) from a specific Generation Resource or ESR to control frequency within the system which is controlled second by second, normally by an Automatic Generation Control (AGC) system.	a. Reg-Down energy is a Resource-specific deployment to increase or decrease generation at a level below the Generation Resource's or ESR's Base Point in response to a change in system frequency. b. Reg-Up energy is a Resource-specific deployment to increase or decrease generation at a level above the Generation Resource's or ESR's Base Point in response to a change in system frequency.
Reg-Down and Reg-Up (for Load Resource) ***Reference: Protocol Section 2***	Load Resource capacity provided by a QSE from a specific Load Resource to control frequency within the system.	a. Reg-Down is a Resource-specific deployment to increase or decrease Load below the Load Resource's Maximum Power Consumption (MPC) limit in response to a change in system frequency. b. Reg-Up is a Resource-specific deployment to increase or decrease Load above the Load Resource's Low Power Consumption (LPC) limit in response to a change in system frequency.
Responsive Reserve (RRS)	Operating reserves on Generation Resources, ESRs, Load Resources, and Resources	RRS may only be deployed as follows:

Reference: Protocol Section 2	capable of providing Fast Frequency Response (FFR) maintained by ERCOT to help control the frequency of the system. RRS on Generation Resources, ESRs, and Controllable Load can be used as energy during an Energy Emergency Alert (EEA) event.	a. Through automatic Governor action or under-frequency relay in response to frequency deviations; b. By electronic signal from ERCOT in response to the need; and c. As ordered by an ERCOT Operator during an EEA or other emergencies.	

ERCOT Contingency Reserve Service (ECRS) ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within ten minutes and operating at a specified output for at least one~~two consecutive~~ hours. b. Controllable Load Resources dispatchable by Security-Constrained Economic Dispatch (SCED) that are capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for at least ~~two~~ one ~~consecutive~~ hours. c. Load Resources that are not Controllable Load Resources and may or may not be controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing ECRS must be capable of reducing Load in response to an Extensible Markup Language (XML) Dispatch Instruction within ten minutes and remain deployed until recalled by ERCOT.	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.4, Deployment and Recall of ERCOT Contingency Reserve Service.	

Non-Spinning Reserve (Non-Spin) Service ***Reference: Protocol Section 2***	a. Off-Line Generation Resource or ESR capacity, or reserved capacity from On-Line Generation Resources or ESRs, capable of being ramped to a specified output level within 30 minutes and operating at a specified output for at least four consecutive hours. b. Controllable Load Resources that are capable of ramping to an ERCOT-instructed consumption level within 30 minutes and consuming at the ERCOT-instructed level for at least four consecutive hours. c. Load Resources that are not Controllable Load Resources and that are not controlled by under-frequency relay. Load Resources that are not Controllable Load Resources providing Non-Spin must be capable of reducing Load in response to an XML Dispatch Instruction within 30 minutes and remain deployed until recalled by ERCOT.	Deployed in response to loss-of-Resource contingencies, Load forecasting error, or other contingency events on the system. See Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.	
Voltage Support Service (VSS) ***Reference: Protocol Section 3.15, Voltage Support***	Reactive capability of a Generation Resource or ESR that is required to maintain transmission and distribution voltages on the ERCOT Transmission Grid within acceptable limits. All Generation Resources and ESRs with a gross rating greater than 20 MVA shall provide VSS.	Direct the scheduling of VSS by providing Voltage Profiles at the Point of Interconnection Bus (POIB). The Generation Resource or ESR is obligated to maintain the published Voltage Profile within its Corrected Unit Reactive Limit (CURL).	

Black Start Service (BSS) ***Reference: Protocol Section 3.14.2, Black Start***	The provision of Generation Resources under a Black Start Agreement, which are capable of self-starting without support from within ERCOT in the event of a Partial Blackout or Blackout.	Provide emergency Dispatch Instructions to begin restoration to a secure operating state after a Partial Blackout or Blackout.
Reliability Must-Run (RMR) Service ***Reference: Protocol Section 3.14.1, Reliability Must Run***	The provision of Generation Resource capacity and energy under an RMR Agreement.	Enter into contractual agreements to retain units required for reliable operations. Direct the operation of those units that otherwise would not operate and that are necessary to provide reliable operations.

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

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

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

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

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

(b) Provide ERCOT the ECRS Load affidavit;

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

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

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

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

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

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

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

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

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

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

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

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

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

[NOGRR211: Replace Section 2.3.3.1 above with the following upon system implementation of NPRR1007:]

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

(1) Generation Resources providing ECRS must be capable of being synchronized and ramped to a specified output level within ten minutes of notification of deployment and run at a specified output level for at least ~~two~~ one ~~consecutive~~ hour~~s~~.

(2) Controllable Load Resource providing ECRS must be capable of ramping to an ERCOT-instructed consumption level within ten minutes and consuming at the ERCOT-instructed level for at least one~~two~~ ~~consecutive~~ hour~~s~~.

Board Report

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

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

(b) Provide ERCOT the ECRS Load affidavit;

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

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

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

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

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

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

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

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

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

(6) ERCOT shall deploy ECRS to meet NERC Reliability Standards and other performance criteria as specified in these Operating Guides and the Protocols by Dispatch Instruction for ECRS through Inter-Control Center Communications Protocol (ICCP) to a QSE representing a Generation Resource in synchronous condenser fast-response mode that is responding to a Frequency Measurable Event (FME) at or below the frequency set point specified in paragraph (3)(b) of Protocol Section 3.18, or under manual deployment when system frequency does not go below the frequency set point

specified in paragraph (3)(b) of Protocol Section 3.18. Dispatch Instructions under this section shall only occur during scarcity conditions, as specified in Protocol Section 6.5.9.4.2, EEA Levels, or in an attempt to recover frequency to meet NERC Standards; and/or Dispatch Instruction for deployment of Load Resources energy via electronic Messaging System.

ERCOT Impact Analysis Report

NOGRR Number	**<u>277</u>**	**NOGRR Title**	**Related to NPRR1282, Ancillary Service Duration under Real-Time Co-optimization**
Impact Analysis Date	April 29, 2025		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1282, Ancillary Service Duration under Real-Time Co-Optimization		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1282.

Board Report

NPRR Number	**1226**	**NPRR Title**	**Estimated Demand Response Data**

Date of Decision	June 24, 2025
Action	Recommended Approval
Timeline	Normal
Estimated Impacts	Cost/Budgetary: Between $100K and $150K Project Duration: 5 to 7 months
Proposed Effective Date	Upon system implementation
Priority and Rank Assigned	Priority – 2026; Rank – 4770
Nodal Protocol Sections Requiring Revision	2.1, Definitions 2.2, Acronyms and Abbreviations 6.3.2, Activities for Real-Time Operations 6.5.7.1.13, Data Inputs and Outputs for the Real-Time Sequence and SCED
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	Since the inception of ERCOT, Demand response from Loads has continuously grown and has become critical to understanding the risks to reliably operating the ERCOT System. Significant amounts of new "Demand Responsive Load" are forecast to continue to increase in the next few years from Loads operating large data centers and those producing hydrogen. Following a presentation on this subject, the Large Flexible Load Task Force (LFLTF) recommended that a better understanding of Demand response occurring in Real-Time is needed to better understand risks during projected critical shortages of generation capacity to serve load. This Nodal Protocol Revision Request (NPRR) directs ERCOT to prepare and publish estimated Demand response data showing aggregated State Estimated Load (SEL) load points selected by ERCOT. The selection of Loads to be aggregated for the report will be based on periodically updated off-line analysis of the frequency and magnitude of reductions observed in historical State Estimator load data that is associated with market signals such as Locational Marginal Prices (LMPs), high levels of summer month ERCOT load, ERCOT-wide appeal(s) through public voluntary energy appeal, or other ERCOT actions.

	Changes in the data will reflect a response by the selected Load attributable to: • Locational Marginal Prices (LMPs); • 4-Coincident Peak (4-CP); • Near 4-CP; • Conservation Alerts; and • Other ERCOT actions.
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	Significant amounts of new "Demand Responsive Load" (well over 13,000 MWs) has been observed and is expected to continue to increase in the next few years. New Loads operating large data centers and those producing hydrogen are expanding their footprint in the ERCOT Region and are expected to be responsive to high ERCOT Real-Time LMPs among other pricing characteristics of retail Loads.
PRS Decision	On 5/9/24, PRS voted unanimously to table NPRR1226 and refer the issue to WMS. All Market Segments participated in the vote. On 2/12/25, PRS voted unanimously to recommend approval of NPRR1226 as amended by the 2/11/25 ERCOT comments. All Market Segments participated in the vote. On 3/12/25, PRS voted unanimously to table NPRR1226. All Market Segments participated in the vote. On 5/14/25, PRS voted unanimously to endorse and forward to TAC the 3/12/25 PRS Report as revised by PRS and 5/5/25 Impact Analysis for NPRR1226 with a recommended priority of 2026 and rank of 4770. All Market Segments participated in the vote.

Board Report

Summary of PRS Discussion	On 5/9/24, the sponsor provided an overview of NPRR1226. On 2/12/25, participants reviewed the 2/11/25 ERCOT comments. On 3/12/25, participants noted the 3/5/25 ERCOT comments for an alternative schedule for the Impact Analysis. On 5/14/25, participants reviewed the 5/5/25 Impact Analysis, discussed an appropriate priority and rank for NPRR1226, and reviewed a desktop edit to relocate a posting requirement within paragraph (2) of Section 6.3.2.
TAC Decision	On 5/28/25, TAC voted unanimously to recommend approval of NPRR1226 as recommended by PRS in the 5/14/25 PRS Report as revised by TAC. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/28/25, TAC reviewed the items below and desktop edits to the Revision Description to better describe the changes within NPRR1226.
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 6/24/25, the ERCOT Board voted unanimously to recommend approval of NPRR1226 as recommended by TAC in the 5/28/25 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1226 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 NPRR1226.
ERCOT Opinion	ERCOT supports approval of NPRR1226.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1226 and believes the market impact for NPRR1226 provides a viable means for Market Participants to obtain a data sub-set of estimated Demand response activity.

Board Report

Sponsor	
Name	Floyd Trefny
E-mail Address	ebmystic@gmail.com
Company	ERCOT Steel Mills
Phone Number	713-516-2745
Cell Number	713-516-2745
Market Segment	Industrial Consumer

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

Comments Received	
Comment Author	**Comment Summary**
WMS 060524	Requested PRS continue to table NPRR1226 for further review by the Demand Side Working Group (DSWG)
WMS 080724	Endorsed NPRR1226 as submitted
ERCOT 080724	Reiterated the importance of ERCOT maintaining the ability and flexibility to curate the location and specific format of the information presented for the dashboards on its website
ERCOT 021125	Proposed redlines to clarify a deliverable product that meets the original request of the sponsor.
ERCOT 030525	Proposed an alternative schedule for completion of the Impact Analysis for NPRR1226 prior to the April 9, 2025 PRS meeting
ERCOT 033125	Proposed an alternative schedule for completion of the Impact Analysis for NPRR1226 prior to the May 14, 2025 PRS meeting

Market Rules Notes

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

- NPRR1239, Access to Market Information (incorporated 2/1/25)
  - Section 6.5.7.1.13

- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)
  - Section 6.5.7.1.13
- NPRR1249, Publication of Shift Factors for All Active Transmission Constraints in the RTM (incorporated 2/1/25)
  - Section 6.5.7.1.13
- NPRR1253, Incorporate ESR Charging Load Information into ICCP (incorporated 4/1/25)
  - Section 6.3.2

Proposed Protocol Language Revision

2.1 DEFINITIONS

State Estimator

A computational algorithm that uses Real-Time inputs from the network's Supervisory Control and Data Acquisition (SCADA) system that measure the network's electrical parameters, including its topology, voltage, power flows, etc., to estimate electrical parameters (such as line flows and Electrical Bus voltages and Loads) in the ERCOT Transmission Grid. The State Estimator's output is a description of the network and all of the values (topology, voltage, power flow, etc.) to describe each Electrical Bus and line included in the system model.

State Estimated Load (SEL)

The amount of instantaneous electric power in MW delivered to consumers at a substation calculated as an output of the State Estimator.

2.2 ACRONYMS AND ABBREVIATIONS

SEL State Estimated Load

6.3.2 Activities for Real-Time Operations

(1) Activities for Real-Time operations begin at the end of the Adjustment Period and conclude at the close of the Operating Hour.

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
Before the start of each SCED run	Update Output Schedules for DSRs	Validate Output Schedules for DSRs Execute Real-Time Sequence
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy prices
During the Operating Hour	Telemeter the Ancillary Service Resource Responsibility for each Resource Telemeter next Operating Hour Ancillary Service Resource Responsibility for an ESR Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered Update COP with actual Resource Status and limits and Ancillary Service Schedules Communicate Resource Forced Outages to ERCOT Communicate to ERCOT Resource changes to Ancillary Service Resource Responsibility via telemetry in the time window beginning 30 seconds prior to the five-minute clock interval and ending ten seconds prior to that five-minute clock interval Submit and update Energy Offer Curves and/or RTM Energy Bids	Communicate all binding Base Points, Dispatch Instructions, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves, and Real-Time Reserve Price Adders for Off-Line Reserves and LMPs for energy and Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder, the total Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand, total Low Ancillary Service Limit (LASL), total High Ancillary Service Limit (HASL), Real-Time On-Line Reliability Deployment Price Adder using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs) Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status

Operating Period	QSE Activities	ERCOT Activities
		Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Monitor ESR State of Charge (SOC) information to ensure Ancillary Service Resource Responsibilities can be met Validate COP information Validate Ancillary Service Trades Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and the sum of each type of available reserves, including total Real-Time reserve amount for On-Line reserves, total Real-Time reserve amount for Off-Line reserves, Real-Time Reserve Price Adders for On-Line Reserves and Real-Time Reserve Price Adders for Off-Line Reserves, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total On-Line LASL, total On-Line HASL, Real-Time On-Line Reliability Deployment Price Adder created for each SCED process<u>, and aggregated data from the estimated Demand response data process as described in Section 6.5.7.1.13</u>. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generator (SOTGs). These prices shall include all Real-Time Reserve Price Adders for On-Line Reserves and Real-Time On-Line Reliability Deployment Price Adders created for each SCED process. These prices shall be posted immediately subsequent to deployment of Base Points

Operating Period	QSE Activities	ERCOT Activities
		from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post on the ERCOT website the projected non-binding LMPs created by each SCED process for each Resource Node, the projected total Real-Time reserve amount for On-Line reserves and Off-Line reserves, the projected Real-Time On-Line Reserve Price Adders and Real-Time Off-Line Reserve Price Adders, and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total emergency DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, total LASL, total HASL, Real-Time On-Line Reliability Deployment Price Adder and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG and SOTG immediately following the end of each Settlement Interval

Operating Period	QSE Activities	ERCOT Activities
		Post the Real-Time On-Line Reliability Deployment Price, Real-Time Reserve Price for On-Line Reserves and the Real-Time Reserve Price for Off-Line Reserves immediately following the end of each Settlement Interval Post parameters as required by Section 6.4.9, Ancillary Services Capacity During the Adjustment Period and in Real-Time, on the ERCOT website

[NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1010, NPRR1077, and NPRR1253: Replace applicable portions of paragraph (2) above with the following upon system implementation for NPRR829, NPRR904, NPRR995, NPRR1000, NPRR1006, NPRR1077, or NPRR1253; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(2) The following table summarizes the timeline for the Operating Period and the activities of QSEs and ERCOT during Real-Time operations where "T" represents any instant within the Operating Hour. The table is intended to be only a general guide and not controlling language, and any conflict between this table and another section of the Protocols is controlled by the other section:

Operating Period	QSE Activities	ERCOT Activities
During the first hour of the Operating Period		Execute the Hour-Ahead Sequence, including HRUC, beginning with the second hour of the Operating Period Review the list of Off-Line Available Resources with a start-up time of one hour or less Review and communicate HRUC commitments and Direct Current Tie (DC Tie) Schedule curtailments Snapshot the Scheduled Power Consumption for Controllable Load Resources
SCED run		Execute SCED and pricing run to determine impact of reliability deployments on energy and Ancillary Service prices
During the Operating Hour	Acknowledge receipt of Dispatch Instructions Comply with Dispatch Instruction Review Resource Status to assure current state of the Resources is properly telemetered	Communicate all binding Base Points, Updated Desired Set Points (UDSPs), Ancillary Service awards, Dispatch Instructions, LMPs for energy, Real-Time MCPCs for Ancillary Services, and for the pricing run as described in Section 6.5.7.3.1, Determination of Real-Time Reliability Deployment Price Adders, the total

	Update COP and telemetry with actual Resource Status and limits and Ancillary Service capabilities Submit and update Ancillary Service Offers Communicate Resource Forced Outages to ERCOT Submit and update Energy Offer Curves and/or RTM Energy Bids	Reliability Unit Commitment (RUC)/Reliability Must-Run (RMR) MW relaxed, total Load Resource MW deployed that is added to the Demand, total Transmission and/or Distribution Service Provider (TDSP) standard offer Load management MW deployed that is added to the Demand, total Emergency Response Service (ERS) MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total Block Load Transfer (BLT) MW that is added to or subtracted from the Demand Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service using Inter-Control Center Communications Protocol (ICCP) or Verbal Dispatch Instructions (VDIs). In communicating Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Monitor Resource Status and identify discrepancies between COP and telemetered Resource Status Restart Real-Time Sequence on major change of Resource or Transmission Element Status Monitor ERCOT total system capacity providing Ancillary Services Validate COP information Validate Ancillary Service Trades Monitor ERCOT control performance Distribute by ICCP, and post on the ERCOT website, System Lambda and the LMPs for each Resource Node, Load Zone and Hub, and Real-Time MCPCs for each Ancillary Service, and for the pricing run as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to the Demand, total ERS MW deployed that is added to the Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, Real-Time Reliability Deployment Price Adder for

		Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Service, and ESR charging created for each SCED process, and aggregated data from the estimated Demand response data process as described in Section 6.5.7.1.13. This data shall be posted immediately subsequent to deployment of Base Points and Ancillary Service awards from SCED with the time stamp the data are effective Post on the ERCOT website the nodal prices for Settlement Only Distribution Generators (SODGs), Settlement Only Distribution Energy Storage Systems (SODESSs), Settlement Only Transmission Generators (SOTGs), and Settlement Only Transmission Energy Storage Systems (SOTESSs). These prices shall include Real-Time Reliability Deployment Price Adders for Energy created for each SCED process~~, and aggregated data from the estimated Demand response data process as described in Section 6.5.7.1.13~~. These prices shall be posted immediately subsequent to deployment of Base Points from SCED with the time stamp the prices are effective Post LMPs for each Electrical Bus on the ERCOT website. These prices shall be posted immediately subsequent to deployment of Base Points from each binding SCED with the time stamp the prices are effective Post every 15 minutes on the ERCOT website the aggregate net injection from Settlement Only Generators (SOGs) and Settlement Only Energy Storage Systems (SOESSs) Post on the ERCOT website the projected non-binding LMPs for each Resource Node and Real-Time MCPCs for each Ancillary Service created by each SCED process and for the projected non-binding pricing runs as described in Section 6.5.7.3.1 the total RUC/RMR MW relaxed, total Load Resource MW deployed that is added to Demand, total TDSP standard offer Load management MW deployed that is added to the Demand, total ERCOT-directed DC Tie MW that is added to or subtracted from the Demand, total BLT MW that is added to or subtracted from the Demand, total ERS MW deployed that are deployed that is added to the Demand, Real-Time Reliability

		Deployment Price Adder for Energy, Real-Time On-Line Reliability Deployment Price Adders for Ancillary Service, and the projected Hub LMPs and Load Zone LMPs. These projected prices shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections Post on the MIS Certified Area the projected non-binding Base Points and Ancillary Service awards for each Resource created by each SCED process. These projected non-binding Base Points shall be posted at a frequency of every five minutes from SCED for at least 15 minutes in the future with the time stamp of the SCED process that produced the projections. In posting Ancillary Service awards, the awards shall be broken out by Ancillary Service sub-type, where applicable Post each hour on the ERCOT website binding SCED Shadow Prices and active binding transmission constraints by Transmission Element name (contingency /overloaded element pairs) Post on the ERCOT website, the Settlement Point Prices for each Settlement Point and the Real-Time price for each SODG, SODESS, SOTG, and SOTESS immediately following the end of each Settlement Interval By Settlement Interval, post the 15-minute Real-Time Reliability Deployment Price for Energy, and the 15-minute Real-Time Reliability Deployment Price for Ancillary Service for each of the Ancillary Services

(3) At the beginning of each hour, ERCOT shall post on the ERCOT website the following information:

(a) Changes in ERCOT System conditions that could affect the security and dynamic transmission limits of the ERCOT System, including:

(i) Changes or expected changes, in the status of Transmission Facilities as recorded in the Outage Scheduler for the remaining hours of the current Operating Day and all hours of the next Operating Day; and

(ii) Any conditions such as adverse weather conditions as determined from the ERCOT-designated weather service;

(b) Updated system-wide Mid-Term Load Forecasts (MTLFs) for all forecast models available to ERCOT Operations, as well as an indicator for which forecast was in use by ERCOT at the time of publication;

(c) The quantities of RMR Services deployed by ERCOT for each previous hour of the current Operating Day; and

(d) Total ERCOT System Demand, from Real-Time operations, integrated over each Settlement Interval.

(4) No later than 0600, ERCOT shall post on the ERCOT website the actual system Load by Weather Zone, the actual system Load by Forecast Zone, and the actual system Load by Study Area for each hour of the previous Operating Day.

(5) ERCOT shall provide notification to the market and post on the ERCOT website Electrical Bus Load distribution factors and other information necessary to forecast Electrical Bus Loads. This report will be published when updates to the Load distribution factors are made. Private Use Network net Load will be redacted from this posting.

[NPRR1010 and NPRR1204: Insert paragraphs (6) and (7) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(6) After every SCED run, ERCOT shall post to the ERCOT website the total capability of Resources available to provide the following Ancillary Service combinations, based on the Resource telemetry from the QSE and capped by the limits of the Resource and, for ESRs, further capped by Ancillary Service SCED duration requirements and current available State of Charge (SOC), for the most recent SCED execution:

(a) Capacity to provide Reg-Up, irrespective of whether it is capable of providing any other Ancillary Service;

(b) Capacity to provide RRS, irrespective of whether it is capable of providing any other Ancillary Service;

(c) Capacity to provide ECRS, irrespective of whether it is capable of providing any other Ancillary Service;

(d) Capacity to provide Non-Spin, irrespective of whether it is capable of providing any other Ancillary Service;

(e) Capacity to provide Reg-Up, RRS, or both, irrespective of whether it is capable of providing ECRS or Non-Spin;

(f) Capacity to provide Reg-Up, RRS, ECRS, or any combination, irrespective of whether it is capable of providing Non-Spin;

(g) Capacity to provide Reg-Up, RRS, ECRS, Non-Spin, or any combination; and

(h) Capacity to provide Reg-Down.

(7) Each week, ERCOT shall post on the ERCOT website the historical SCED-interval data described in paragraph (6) above.

6.5.7.1.13 Data Inputs and Outputs for the Real-Time Sequence and SCED

(1) Inputs: The following information must be provided as inputs to the Real-Time Sequence and SCED. ERCOT may require additional information as required, including:

(a) Real-Time data from TSPs including status indication for each point if that data element is stale for more than 20 seconds;

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

(a) Real-Time data from TSPs and DCTOs including status indication for each point if that data element is stale for more than 20 seconds;

(i) Transmission Electrical Bus voltages;

(ii) MW and MVAr pairs for all transmission lines, transformers, and reactors;

(iii) Actual breaker and switch status for all modeled devices; and

(iv) Tap position for auto-transformers;

(b) State Estimator results (MW and MVAr pairs and calculated MVA) for all modeled Transmission Elements;

(c) Transmission Element ratings from TSPs;

[NPRR857: Replace paragraph (c) 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:]

(c) Transmission Element ratings from TSPs and DCTOs;

(i) Data from the Network Operations Model:

(A) Transmission lines – Normal, Emergency, and 15-Minute Ratings (MVA); and

(B) Transformers and Auto-transformers – Normal, Emergency, and 15-Minute Ratings (MVA) and tap position limits;

(ii) Data from QSEs:

(A) Generator Step-Up (GSU) transformers tap position;

(B) Resource HSL (from telemetry); and

(C) Resource LSL (from telemetry); and

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

[NPRR857: Replace paragraph (d) 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:]

(d) Real-Time weather, from Wind-powered Generation Resources (WGRs), and where available from TSPs, DCTOs, or other sources. ERCOT may elect to obtain other sources of weather data and may utilize such information to calculate the dynamic limit of any Transmission Element.

(2) ERCOT shall validate the inputs of the Resource Limit Calculator as follows:

(a) The calculated SURAMP and SDRAMP are each greater than or equal to zero; and

(b) Other provision specified under Section 3.18, Resource Limits in Providing Ancillary Service.

[NPRR1010: Delete paragraph (2) above upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly.]

(3) Outputs for ERCOT Operator information and possible action include:

(a) Operator notification of any change in status of any breaker or switch;

(b) Lists of all breakers and switches not in their normal position;

(c) Operator notification of all Transmission Element overloads detected from telemetered or State-Estimated data;

(d) Operator notification of all Transmission Element security violations; and

(e) Operator summary displays:

(i) Transmission system status changes;

(ii) Overloads;

(iii) System security violations; and

(iv) Base Points.

(4) Every hour, ERCOT shall post on the MIS Secure Area the following information:

(a) Status of all breakers and switches used in the NSA except breakers and switches connecting Resources to the ERCOT Transmission Grid;

(b) All binding transmission constraints and the contingency or overloaded element pairs that caused such constraint; and

(c) Shift Factors, including Private Use Network Settlement Points, by Resource Node, Hub, Load Zone, and DC Tie.

[NPRR1239 and NPRR1249: Replace applicable portions of paragraph (4) above with the following upon system implementation:]

(4) Every hour, ERCOT shall post on the MIS Secure Area, except where otherwise stated in this paragraph (4), the following information:

(a) Status of all breakers and switches used in the NSA except breakers and switches connecting Resources to the ERCOT Transmission Grid;

(b) All binding transmission constraints and the contingency or overloaded element pairs that caused such constraint; and

(c) On the ERCOT website, Shift Factors for all active transmission constraints, including Private Use Network Settlement Points, by Resource Node, Hub, Load Zone, and DC Tie.

(5) Sixty days after the applicable Operating Day, ERCOT shall post on the MIS Secure Area, the following information:

(a) Hourly transmission line flows and voltages from the State Estimator, excluding transmission line flows and voltages for Private Use Networks; and

(b) Hourly transformer flows, voltages and tap positions from the State Estimator, excluding transformer flows, voltages, and tap positions for Private Use Networks.

[NPRR1239: Replace paragraph (5) above with the following upon system implementation:]

(5) Sixty days after the applicable Operating Day, ERCOT shall post on the ERCOT website, the following information:

(a) Hourly transmission line flows and voltages from the State Estimator, excluding transmission line flows and voltages for Private Use Networks; and

(b) Hourly transformer flows, voltages and tap positions from the State Estimator, excluding transformer flows, voltages, and tap positions for Private Use Networks.

(6) Notwithstanding paragraph (5) above, ERCOT, in its sole discretion, shall release relevant State Estimator data less than 60 days after the Operating Day if it determines the release is necessary to provide complete and timely explanation and analysis of unexpected market operations and results or system events including, but not limited to, pricing anomalies, recurring transmission congestion, and system disturbances. ERCOT's release of data under this paragraph shall be limited to intervals associated with the unexpected market or system event as determined by ERCOT. The data release shall be made available simultaneously to all Market Participants.

(7) Every hour, ERCOT shall post on the ERCOT website, the sum of ERCOT generation, and flow on the DC Ties, all from the State Estimator.

(8) After every SCED run, ERCOT shall post to the ERCOT website the sum of the HDL and the sum of the LDL for all Generation Resources On-Line and Dispatched by SCED.

[NPRR1246: Replace paragraph (8) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(8) After every SCED run, ERCOT shall post to the ERCOT website the sum of the HDL and the sum of the LDL for all Generation Resources and ESRs On-Line and Dispatched by SCED.

(9) Sixty days after the applicable Operating Day, ERCOT shall post to the ERCOT website the summary LDL and HDL report from paragraph (8) above and include instances of manual overrides of HDL or LDL, including the name of the Generation Resource and the type of override.

[NPRR1246: Replace paragraph (9) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(9) Sixty days after the applicable Operating Day, ERCOT shall post to the ERCOT website the summary LDL and HDL report from paragraph (8) above and include instances of manual overrides of HDL or LDL, including the name of the Generation Resource or ESR and the type of override.

(10) No sooner than sixty days after the applicable Operating Day, ERCOT shall provide to the appropriate Technical Advisory Committee (TAC) subcommittee instances of manual overrides of HDL or LDL, including the name of the Generation Resource, the reason for the override, and, as applicable, the cost as calculated in Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment.

[NPRR1246: Replace paragraph (10) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(10) No sooner than sixty days after the applicable Operating Day, ERCOT shall provide to the appropriate Technical Advisory Committee (TAC) subcommittee instances of manual overrides of HDL or LDL, including the name of the Generation Resource or ESR, the reason for the override, and, as applicable, the cost as calculated in Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment.

(11) After every SCED run, ERCOT shall post to the MIS Certified Area, for any QSE, instances of a manual override of the HDL or LDL for a Generation Resource, including the original and overridden HDL or LDL.

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

(11) After every SCED run, ERCOT shall post to the MIS Certified Area, for any QSE, instances of a manual override of the HDL or LDL for a Generation Resource or ESR, including the original and overridden HDL or LDL.

(12) After every SCED run, ERCOT shall prepare and publish estimated Demand response data showing aggregated State Estimated Load (SEL) load points selected by ERCOT. The selection of Loads to be aggregated for the report will be based on periodically updated off-line analysis of the frequency and magnitude of reductions observed in historical State Estimator load data that is associated with market signals such as Locational Marginal Prices (LMPs), high levels of summer month ERCOT load, ERCOT-wide appeal(s) through public voluntary energy appeal, or other ERCOT actions.~~on the ERCOT website data for the Demand Response Monitor containing analysis of the Demand response of aggregated State Estimated Load (SEL) exhibiting a significant decrease in consumption likely due to responses to Locational Marginal Prices (LMPs), 4-Coincident Peak (4CP), ERCOT-wide appeal(s) through the public news media for voluntary energy conservation, or other ERCOT actions. The Demand response shall be calculated by comparing the positive difference in peak consumption of a Load in the past two hours to the current SEL of selected substations.~~

~~(a) Selection of Loads to be used in the Demand Response Monitor would be by off-line analysis of various Loads' responses observed in historical State Estimator data. ERCOT may aggregate sub-sets of SEL for use by the ERCOT operators in Real-Time.~~

~~(b) The ERCOT website posting will include a graphical depiction of the aggregate Demand response observed compared to the average LMP from each SCED run, plotted as separate time series in descending chronological order, for the past two hours of SCED executions.~~

ERCOT Impact Analysis Report

NPRR Number	1226	NPRR Title	Estimated Demand Response Data
Impact Analysis Date	May 5, 2025		
Estimated Cost/Budgetary Impact	Between $100K and $150K		
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: 5 to 7 months		
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: • Energy Management System 38% • Enterprise Integration Corp Services 38% • Data and Information Products 12% • Web Communications 10% • Content Management 2%		
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	1229	NPRR Title	Real-Time Constraint Management Plan Cost Recovery Payment
Date of Decision	June 24, 2025		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $100K and $200K Project Duration: 8 to 10 months		
Proposed Effective Date	Upon system implementation for Section 9.5.3; the first of the month following Public Utility Commission of Texas (PUCT) approval for the remaining sections		
Priority and Rank Assigned	Priority – 2028; Rank – 5100		
Nodal Protocol Sections Requiring Revision	4.4.9.3.3, Energy Offer Curve Cost Caps 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery Payment (new) 6.6.3.10, Real-Time Constraint Management Plan Cost Recovery Charge (new) 6.6.3.11, Miscellaneous Invoice for Cost Recovery Payments and Charges for a Real-Time Constraint Management Plan (new) 9.5.3, Real-Time Market Settlement Charge Types		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) creates a process that compensates a Qualified Scheduling Entity (QSE) when a Constraint Management Plan (CMP) or ERCOT-directed switching instruction implemented by ERCOT causes the trip of a Generation Resource when it would not have occurred absent those conditions.		
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	The changing Resource mix coupled with the dynamic of substantially increased load growth has put more strain on the ERCOT grid and the management of power flows. This is evidenced by a proliferation of Generic Transmission Constraints (GTCs) and CMPs, and the occasional use of ERCOT-directed switching instructions. Last summer, to support matching the available supply to demand, ERCOT implemented atypical transmission procedures or configurations to improve energy transfers across the system. Because of the enormous power transfer from south Texas to central and north Texas, ERCOT had to redispatch a vast number of Resources with very low Shift Factors and directed the switching of transmission equipment in an atypical configuration that placed a thermal Resource closer to risk of tripping to manage a post-contingency overload. A Resource should be compensated if the Resource is ultimately tripped Off-Line due to ERCOT actions taken in an effort to support reliability. A Resource that experiences a Forced Outage due to actions taken by ERCOT to benefit the remaining ERCOT System should be allowed to recover certain costs associated with that Forced Outage. The language and concepts added by this NPRR are borrowed from a similar mechanism with make-whole provisions (High Dispatch Limit (HDL) override payments, Outage Schedule Adjustment (OSA) make-whole payments, Reliability Unit Commitment (RUC) make-whole payments). In addition, there is consideration for Outage costs due to a Forced Outage resulting from an enacted CMP. The Settlement would be handled as a Settlement dispute initiated by the QSE.
PRS Decision	On 6/13/24, PRS voted unanimously to table NPRR1229 and refer the issue to ROS and WMS. All Market Segments participated in the vote. On 3/12/25, PRS voted to recommend approval of NPRR1229 as amended by the 3/6/25 WMS comments as revised by PRS. There were three opposing votes from the Consumer (Residential Consumer, City of Eastland, Occidental) Market Segment and one

	abstention from the Independent Power Marketer (IPM) (Tenaska) Market Segment. All Market Segments participated in the vote. On 4/9/25, PRS voted to endorse and forward to TAC the 3/12/25 PRS Report as amended by the 3/20/25 ERCOT comments and the 4/8/25 Impact Analysis for NPRR1229 with a recommended effective date of upon system implementation for Section 9.5.3 with a recommended priority of 2028 and rank of 5100 and the first of the month following PUCT approval for the remaining sections. There were two opposing votes from the Consumer (Residential Consumer, Occidental) Market Segment and one abstention from the Independent Generator (EDF Renewables) Market Segment. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/13/24, the sponsor provided an overview of NPRR1229, the 5/8/24 STEC comments, and the 6/12/24 STEC comments. Participants requested additional review of operational and Settlement components of NPRR1229 at ROS and WMS. On 3/12/25, participants reviewed the 3/6/25 WMS comments and proposed a desktop edit to correct a renumbered paragraph reference. Opponents in the Consumer Market Segment expressed concerns that NPRR1229, like NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs, are inconsistent with the market design and create improper incentives. On 4/9/25, participants reviewed the 3/20/25 ERCOT comments. ERCOT Staff provided an overview of the near-term manual and longer-term automated implementation of NPRR1229. Participants requested the project work to automate NPRR1229 be prioritized far enough in the future to allow for a review of the size and frequency of any manual charges/payments made under NPRR1229 by stakeholders to determine if the automation is justified.
TAC Decision	On 4/23/25, TAC voted to recommend approval of NPRR1229 as recommended by PRS in the 4/9/25 PRS Report. There were eight opposing votes from the Consumer (6) (Residential Consumer, OPUC, Lyondell Chemical, CMC Steel, City of Eastland, City of Dallas) and Independent Retail Electric Provider (IREP) (2) (Rhythm Ops, Demand Control 2) Market Segments and one abstention from the IREP (APG&E) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 4/23/25, TAC reviewed the items below. Opponents reiterated concerns that NPRR1229 shifts and socializes costs to the entire market when the charges should be borne by the individual generators. Supporters noted the infrequency of the covered events existing requirements for reviewing Settlement disputes, and

	highlighted the assigned priority/rank will delay any associated project spending from NPRR1229 for several years.
Explanation of Opposing TAC Votes	**Consumer/Lyondell Chemical** – Lyondell Chemical opposed NPRR1229 for the same reasons it opposed NPRR1190, High Dispatch Limit Override Provision for Increased Load Serving Entity Costs. The explicit reasons for Lyondell Chemical's opposition are stated below, as adapted from Joint Consumer Comments Opposing NPRR1190, dated October 2, 2024, to which Lyondell Chemical was a party. A major reason the ERCOT market adopted nodal dispatch and pricing in PUCT Substantive Rule 25.501, "Wholesale Market Design for the Electric Reliability Council of Texas" was to avoid paying generation owners for power that was scheduled but not deliverable. Prior to the implementation of the rule, the ERCOT zonal market design operated under an approach that "all schedules must flow" and that Market Participants could be compensated with "OOME Down" payments for any portion of the scheduled power that was not deliverable. Ultimately, the PUCT deemed the OOME payment approach untenable in the long run and ordered ERCOT to institute nodal pricing instead, putting the risk of power delivery on Market Participants. This is known as the direct assignment of congestion costs, which is reflected in the Real-Time nodal pricing at a particular generator node or set of nodes. Through this rule, the PUCT instituted a policy that no Market Participant has an absolute right to flow power across the grid under all circumstances. The payments proposed under NPRR1229 will force consumers to subsidize Market Participants when grid conditions require curtailment. Over the past two decades, Market Participants have had ready access to alternative sources of power through purchases in the liquid commercial bilateral power market and have the capability to make arrangements in advance to handle a wide range of contingencies that might hinder the delivery of power from an owned or contracted Resource. These alternative arrangements assist both Resource adequacy in the long run and reliability in Real-Time. Just as other consumers would not pay for a generator if Security-Constrained Economic Dispatch (SCED) did not deploy a Resource at its full output, other power consumers should not have to subsidize Resources that are dispatched down by ERCOT by other means than SCED to maintain grid reliability. **Consumer/Residential Consumer** – Residential Consumer agrees with the comments of Lyondell Chemical above. **Consumer/OPUC** – OPUC agrees with the comments of Lyondell Chemical above.

	Consumer/CMC Steel – CMC Steel agrees with the comments of Lyondell Chemical above. **Consumer/City of Eastland** – City of Eastland agrees with the comments of Lyondell Chemical above. **Consumer/City of Dallas** – City of Dallas agrees with the comments of Lyondell Chemical above. **IREP/Rhythm Ops** – Rhythm Ops agrees with the comments of Lyondell Chemical above. **IREP/Demand Control 2** – Demand Control 2 agrees with the comments of Lyondell Chemical above.
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 6/24/25, the ERCOT Board voted to recommend approval of NPRR1229 as recommended by TAC in the 4/23/25 TAC Report. There was one opposing vote.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1229 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 NPRR1229.
ERCOT Opinion	ERCOT has no opinion on NPRR1229. NPRR1229 is primarily focused on a cost allocation issue; and determines the entities responsible for bearing the costs due to Generation Resources tripping Off-Line if the trip is attributable to a CMP. NPRR1229 does not impact reliability or market design outcomes.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1229 and believes the market impact for NPRR1229 enables a QSE to submit a Settlement dispute seeking to recover costs attributable to a CMP under certain conditions that were previously not allowed.

Board Report

Sponsor	
Name	Lucas Turner
E-mail Address	lucas@stec.org
Company	South Texas Electric Cooperative, Inc. (STEC)
Phone Number	361-485-6200
Cell Number	361-212-6308
Market Segment	Cooperative

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**
ERCOT 050724	Provided an initial list of concerns with the as-submitted version of NPRR1229 for additional stakeholder discussion
STEC 050824	Provided additional redlines to include Section 6.6.3.10 to address the charge needed to fund the proposed payment
STEC 061224	Provided additional redlines to the 5/8/24 STEC comments to implement a manual calculation for billing and provide additional clarity and efficiency
WMS 071124	Requested PRS continue to table NPRR1229 for further review by the Wholesale Market Working Group (WMWG)
ROS 071124	Requested PRS continue to table NPRR1229
STEC 092024	Proposed additional clarifying revisions to the 6/12/24 STEC comments based on stakeholder discussions at WMS and the WMWG
Residential Consumer 101624	Requested NPRR1229 remain tabled until the ERCOT Board addresses NPRR1190

Board Report

STEC 110424	Proposed additional clarifying revisions to the 9/20/24 STEC comments
STEC 010225	Proposed additional clarifying revisions to the 11/4/24 STEC comments
ERCOT 012825	Proposed additional clarifying revisions to the 1/2/25 STEC comments
ROS 020625	Advised PRS that ROS determined the issues are financial in nature and ROS has no recommendation at this time
STEC 022625	Proposed additional revisions to the 1/28/25 ERCOT comments adding a reporting threshold when the annual sum of demonstrable financial losses included exceeds $3.5 million
WMS 030625	Endorsed NPRR1229 as amended by the 2/26/25 STEC comments as revised by WMS to lower the reporting threshold to $1.5 million
ERCOT 032025	Provided additional redlines to add Real-Time Constraint Management Plan Cost Recovery Payments to the types of payments subject to Real-Time Energy Offer Curve Offer Curve Cost Caps (RTEOCOST) in Section 4.4.9.3.3

Market Rules Notes

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

- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era (incorporated 4/1/25)
  - Section 4.4.9.3.3

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

- NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
  - Section 9.5.3
- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  - Section 9.5.3

Proposed Protocol Language Revision

4.4.9.3.3 Energy Offer Curve Cost Caps

(1) The following Energy Offer Curve Cost Caps must be used for the purpose of make-whole Settlements, Real-Time High Dispatch Limit Override Energy Payments, Real-Time Constraint Management Plan Cost Recovery Payments, and Voltage Support Service Payments:

(a) Nuclear = $15.00/MWh;

(b) Coal and Lignite = $18.00/MWh;

(c) Combined Cycle greater than 90 MW = 9 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(d) Combined Cycle less than or equal to 90 MW = 10 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(e) Gas - Steam Supercritical Boiler = 10.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(f) Gas Steam Reheat Boiler = 11.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(g) Gas Steam Non-reheat or boiler without air-preheater = 14.5 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(h) Simple Cycle greater than 90 MW = 14 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(i) Simple Cycle less than or equal to 90 MW = 15 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(j) Reciprocating Engines = 16 MMBtu/MWh * ((Percentage of FIP * FIP) + (Percentage of FOP * FOP))/100, as specified in the Energy Offer Curve;

(k) Hydro = $10.00/MWh;

(l) Other = SWCAP;

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

(l) Other = DASWCAP or RTSWCAP;

(m) RMR Resource = SWCAP;

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

(m) RMR Resource = effective Value of Lost Load (VOLL);

(n) Wind Generation Resources = $0.00/MWh; and

(o) PhotoVoltaic Generation Resource (PVGR) = $0.00/MWh.

[NPRR1246: Insert item (p) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(p) Energy Storage Resource (ESR) = $0.00/MWh.

(2) ERCOT shall produce an annual report each April that provides the amount of DAM and RUC Make-Whole Payments during the previous calendar year for Resources categorized as Other, per item (1)(l) above, as a percentage of the total amount of DAM and RUC Make-Whole Payments made during the previous calendar year. The report shall be based on final Settlements and include the total number of Resources classified as Other. ERCOT shall present this report annually to the appropriate Technical Advisory Committee (TAC) subcommittee. If there are no Make-Whole Payments for Resources categorized as Other for a given calendar year, then ERCOT will not be required to produce the annual report.

(3) Items in paragraphs (1)(c) and (d) above are determined by capacity of largest simple-cycle combustion turbine in the train selected.

(4) The FIP and FOP used to calculate the Energy Offer Curve Cap for Make-Whole Payment calculation purposes shall be the FIP or FOP for the Operating Day. In the event the Energy Offer Curve Cap for Make-Whole Payment calculation purposes must be calculated before the FIP or FOP is available for the particular Operating Day, the FIP and FOP for the most recent preceding Operating Day shall be used. Once the FIP and FOP are available for a particular Operating Day, those values shall be used in the calculations. If the percentage fuel mix is not specified or if no Energy Offer Curve exists, then the minimum of FIP or FOP shall be used.

[NPRR1216: Insert paragraph (5) below upon system implementation:]

(5)	During an Emergency Offer Cap (ECAP) Effective Period, the SWCAP used for purposes of calculating the Energy Offer Curve Cost Caps shall be set to the maximum value of SWCAP that was effective for the Operating Day.

[NPRR1216: Replace paragraph (5) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(5) During an ECAP Effective Period, for purposes of calculating the Energy Offer Curve Cost Caps, the DASWCAP shall be set to the DASWCAP that was used to clear the DAM, and the VOLL shall be set to the maximum value VOLL that was effective for the Operating Day.

6.6.3.9 Real-Time Constraint Management Plan Cost Recovery~~Energy~~ Payment

(1) If a Generation Resource trips Off-Line from a transmission equipment operation that would have normally not tripped the unit Off-Line but for~~as a result of or subsequent to~~ the activation~~implementation~~ of a Constraint Management Plan (CMP) or a Verbal Dispatch Instruction (VDI) issued by ERCOT ~~directly impacting transmission equipment connected to the Generation Resource~~ which subjects a Generation Resource to N-1 contingency that could trip the Generation Resource Off-Line ~~or ERCOT issues a Verbal Dispatch Instruction (VDI) to a Generation Resource or its Transmission Operator to operate its equipment to produce the same effect, and the QSE suffers a demonstrable financial loss,~~ the QSE may be eligible for a Real-Time Constraint Management Plan Cost Recovery~~Energy~~ Payment, as calculated in paragraph (6) below, upon providing documented proof of the financial and repair cost~~that loss~~. ~~The~~A Generation Resource impacted by the CMP or VDI shall not be eligible for ~~this~~a CMP cost recovery payment under any of the following two conditions:

(a) ~~i~~If the Resource Entity for this Generation Resource agreed with the CMP to subject the Generation Resource to the N-0 condition.

(b) ~~A Generation Resource shall not be eligible for this payment i~~If ERCOT must issue a V~~erbal~~ D~~ispatch~~ I~~nstruction~~ to open the Generation Resource's breaker due to the Generation Resource improperly following ERCOT instructions without ~~the Generation Resource~~ notifying ERCOT that the CMP or VDI ~~doing so~~ would physically harm the Resource. ~~In order to qualify for this payment the QSE must:~~

~~(a) Have impacted the Generation Resource On-line with breaker closed;~~

~~(b) The Generation Resource tripped Off-Line from a transmission equipment operation in an N-1 contingency following activation of a CMP directly impacting transmission equipment connected to the Generation Resource or an equivalent VDI issued by ERCOT to the Generation Resource or its Transmission Operator~~

~~to operate equipment to produce the same effectHave tripped Off-Line following implementation of a CMP directly impacting transmission equipment connected to the Generation Resource or a VDI to the Generation Resource or its Transmission Operator to operate equipment to produce the same effect;~~

~~(c) Have incurred a demonstrable financial loss in consequence of the CMP directly impacting transmission equipment connected to the Generation Resource or a VDI to the Generation Resource or its Transmission Operator to operate equipment to produce the same effect; and~~

(2) To qualify for a Constraint Management Plan Cost Recovery Payment the following conditions must be met:

(a) The CMP or VDI must have financially impacted the Generation Resource that tripped Off-Line;

(b) The Generation Resource must have tripped Off-Line from a transmission equipment operation in an N-1 contingency following activation of a CMP directly impacting transmission equipment connected to the Generation Resource or an equivalent VDI issued by ERCOT to the Generation Resource or its Transmission Operator to operate equipment to produce the same effect; and

(c~~d~~) The QSE must ~~F~~file a timely Settlement and billing dispute, including the following items:

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

(ii) The dollar amount and calculation of the demonstrable financial loss by Settlement Interval and the total repair cost for the CMP event, including:

(A) Demonstrable ~~F~~financial losses (excluding lost opportunity costs) while Resource is in an Outage caused by the CMP or equivalent VDI unit trip Off-Line and with a Resource Status of OUT, associated with one of the following:

(1) QSEs representing Generation Resources in their portfolio ~~with the outage for a Resource~~ with a bilateral contract to sell energy at its Resource Node~~Variable cost components of DAM obligations~~; or

(2) Incremental costs incurred by a QSE in the Real-Time Market (RTM) to serve its Load if the outage for the Resource is in the same QSE portfolio as the Load, and causes the QSE to be short energy compared to its Load for the intervals affected by the outage~~Energy purchase or sale~~

~~provisions of bilateral contracts, including wholesale power contracts or other contracts of Electric Cooperatives (ECs) or Municipally Owned Utilities (MOUs) to serve their Loads~~; or

(3) ~~Opportunity costs in the Real-Time Market (RTM) if the Resource does not meet items (1) or (2) above~~Variable cost components of DAM obligations; and

(B) Actual ~~and indirect~~ costs incurred to repair the plant equipment directly attributable to the~~due a~~ Forced Outage caused by the CMP activation or equivalent VDI. The maximum amount recoverable shall be capped at $500,000 per event. Such costs include, but are not limited to:

(1) Costs associated with a Forced Outage if the result of the trip is due to the implementation of the CMP or equivalent VDI;

(2) Additional staff or contractor time as a result of the Forced Outage;

(3) Costs of equipment rental (including but not limited to cranes, manlifts, welding machines, etc.);

(4) Costs of facility rentals and other incidental incremental costs incurred by the Resource~~,~~ or its QSE~~, or its fuel supplier (e.g. mine-related expenses)~~ created by the Forced Outage; and

(5) The cost of materials to be repaired ~~or replaced~~ that is a direct result of the Forced Outage.

(C) Costs covered under paragraphs (A) and (B) above do not include:

(1) Capital expenditures.

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

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

(3) If the total Settlement amount of demonstrable financial losses included within Constraint Management Plan Cost Recovery Payments, as defined in paragraph (2)(c)(ii)(A) above, exceeds $~~3~~1.5 million in a calendar year, ERCOT will report to the Technical Advisory Committee (TAC) the causes of the payments and provide recommendations on how to reduce the costs based on the eligible demonstrable financial loss criteria in paragraph (2)(c)(ii)(A) above.

(4~~3~~~~2~~) The ~~time frame to be included~~period used to calculate the Constraint Management Plan Cost Recovery~~ in CMP Energy~~ Payment calculation will start at the Settlement Interval of initial trip and will conclude in the Settlement Interval at the soonest of:

(a) The Generation Resource is On-Line and available for Dispatch as per telemetry; or

(b) Ninety~~-~~-six Operating Hours after the Resource trips Off-Line~~The first hour of availability for ERCOT Dispatch (e.g. Resource Status other than OUT) as per the COP.; or~~

~~(c) The latest planned end of the Generation Resource Outage as shown in the Outage SchedulerTenFour Operating Days following the first Operating Day after the Resource trips Off-Line.~~

(5~~4~~~~3~~) ERCOT may request additional supporting documentation or explanation with respect to the submitted materials within ~~15~~60 Business Days of receipt. Additional information requested by ERCOT must be provided by the QSE within 15 Business Days of ERCOT's request. ERCOT will provide Notice of its acceptance or rejection of the claim for the Real-Time Constraint Management Plan Energy Payment within 15 Business Days of the updated submission, or request additional clarification as needed.

~~(4) The Energy Offer Curve used to calculate the Real-Time Constraint Management Plan Energy Payment will be the current Mitigated Offer Curve for the Generation Resource that was effective for the disputed interval(s) when the CMP or equivalent VDI was active.~~

(65~~45~~) The Startup costs available for the Generation Resource will be based on~~limited to the lesser of~~ the Resource's Category Startup Offer Generic Cap unless ERCOT has approved verifiable unit-specific Startup Costs for the Resource. If applicable, the calculated Verifiable Startup costs will be based on FIP or FOP fuel prices for the Operating Day when the Resource tripped Off-Line.~~:~~

~~(a) The most recent valid Day-Ahead Startup Offer received for the Generation Resource; or~~

~~(b) The Day-Ahead Startup Cap for the Resource's Category Startup Offer Generic Cap unless ERCOT has approved verifiable unit-specific Startup Costs for the Resource.~~

(76~~56~~) The Constraint Management Plan Cost Recovery P~~p~~ayment shall be calculated for the period described in paragraphs (4~~3~~) ~~and (5)~~ above as follows~~ whereas the similar variables included herein shall have the same meaning as defined in Section 5.6.5.2, RUC Make-Whole Payment and RUC Clawback Charge for Resources, and Section 5.7.1.1, RUC Guarantee~~:

$$CMPCRAMT_{q,\,r,\,p,\,i} = (-1) * (CMPFALA_{q,\,r,\,p,\,i} + CMPRALA_{q,\,r,\,p,\,i} + CMPSUPR_{q,\,r,\,p,\,i})$$

Where:

$$CMPFALA_{q,\,r,\,p,\,i} = \text{Min}\,(CMPFAL_{q,\,r,\,p,\,i},\ \text{Max}\,(0,\ (RTSPP_{p,\,i} - RTRSVPOR_{i} - RTRDP_{i} - RTEOCOST_{q,\,r,\,p,\,i}) * (1/4) * CMPHSL_{q,\,r,\,p,\,h}))$$

And,

Where the repair costs are allocated equally over the intervals corresponding to the period determined in paragraph (4~~3~~) above:

$$CMPRALA_{q,\,r,\,p,\,i} = \text{Min}\,(\$500{,}000,\ CMPRAL_{q,\,r,\,p}) \ /\ \text{Total number of intervals in CMP period}$$

And,

Where on the first Operating Day of the period determined in paragraph (4~~3~~) above, a cold startup cost is allocated evenly across the CMP event intervals. Subsequent Operating Days in the CMP event will not have startup cost allocations.

$$CMPSUPR_{q,\,r,\,p,\,i} = CMPSUCAP_{q,\,r,\,p,\,cold} \ /\ \text{Total number of CMP period intervals in the first Operating Day of the CMP event}$$

~~$CMPEAMT = (-1)\{\sum_{i} (\text{Max}\,(0,\ (RTSPP_{p} - MOC_{q,\,r,\,h})) * HSL_{q,\,r,\,h} * (1/4))\} + SUPR_{q,\,p,\,r} + CMPLOAL_{q,\,r,\,p,\,i}\}$~~

~~$SUPR_{q,\,p,\,r} = \text{Min}(SUO_{q,\,p,\,r},\ SUCAP_{q,\,p,\,r})$~~

~~Where: If the QSE submitted a validated Three-Part Supply Offer for the Resource,~~

~~Then, $SUPR_{q,\,r,\,s} = \text{Min}\,(SUO_{q,\,r,\,s},\ SUCAP_{q,\,r,\,s})$~~

~~Otherwise, $SUPR_{q,\,r,\,s} = SUCAP_{q,\,r,\,s}$~~

~~If ERCOT has approved verifiable Startup Costs and minimum-energy costs for the Resource,~~

~~Then, $SUCAP_{q,\,r,\,s}$ = verifiable Startup Costs$_{q,\,r,\,s}$~~

~~Otherwise, $SUCAP_{q,\,r,\,s} = RCGSC_{s}$~~

The above variables are defined as follows:

Variable	Unit	Definition
CMPCRAMT $_{q, r, p, i}$	$	*Constraint Management Plan Cost Recovery Amount* per QSE per Generation Resource—The payment to QSE *q* during eligible intervals of a Resource trip offline from an ERCOT-issued CMP unit trip or equivalent VDI for Resource *r*, at Settlement Point *p* for the 15-minute Settlement Interval *i*. Where, for a Combined Cycle Resource, *r* is a Combined Cycle Train.
CMPFALA $_{q, r, p, i}$	$	*Constraint Management Plan Financial Attested Losses Allowed per QSE per Generation Resource*— The payment for financial attested losses to QSE *q* for an ERCOT-issued CMP unit trip or equivalent VDI for Generation Resource *r*, at Settlement Point *p* for the 15-minute Settlement Interval *i*. Where, for a Combined Cycle Resource, *r* is a Combined Cycle Train.
CMPFAL $_{q, r, p, i}$	$	*Constraint Management Plan Demonstrable Financial Attested Losses* —The demonstrable financial loss to QSE *q* for Resource *r*, at Settlement Point *p* due to an ERCOT-issued CMP unit trip or equivalent VDI, as attested by the QSE, and in accordance with costs described in paragraph (2)(c)(~~iii~~)(~~b~~)(A) above, for the 15-minute Settlement Interval *i*. Where, for a Combined Cycle Resource, *r* is a Combined Cycle Train.
CMPRALA $_{q, r, p, i}$	$	*Constraint Management Plan Repair Cost Attested Losses Allowed per QSE per Generation Resource* — The payment for repair costs attested losses to QSE *q* for an ERCOT-issued CMP unit trip or equivalent VDI for Generation Resource *r*, at Settlement Point *p* for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Resource, *r* is a Combined Cycle Train.
CMPRAL $_{q, r, p}$	$	*Constraint Management Plan Repair Attested Losses*— The total Generation Resource repair cost due to trip off-Line of Resource following implementation of an ERCOT-issued CMP or equivalent VDI as attested by the QSE *q* and in accordance with costs described in paragraph (2)(c)(~~iii~~)(~~b~~)(B) above. For a combined cycle Resource, *r* is a Combined Cycle Train.
CMPSUPR $_{q, r, p, i}$	$/Start	*Startup Price per start*—The Settlement price for Resource *r* represented by QSE *q* for the cold start, for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RTEOCOST $_{q, r, p, i}$	$/MWh	*Real-Time Energy Offer Curve Cost Cap*—The Energy Offer Curve Cost Cap for Resource *r* represented by QSE *q*, for the Resource's generation above the LSL for the Settlement Interval *i*. See Section 4.4.9.3.3, Energy Offer Curve Cost Caps. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
CMPHSL $_{q, r, p, h}$	MW	*Constraint Management Plan High Sustained Limit*— The High Sustained Limit (HSL) of Generation Resource *r* represented by QSE *q*, as submitted in the Current Operating Plan (COP), for the hour the Resource tripped off-line. Where for a Combined Cycle Resource, *r* is the Combined Cycle Generation Resource within the Combined Cycle Train that was online when the Resource tripped Off-Line.

Variable	Unit	Definition
$RTSPP_{p,\ i}$	\$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.
$RTRSVPOR_{\ i}$	\$/MWh	*Real-Time Reserve Price for On-Line Reserves* - The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval *i*.
$RTRDP_{\ i}$	\$/MWh	*Real-Time On-Line Reliability Deployment Price* - The Real-Time price for the 15-minute Settlement Interval *i*, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
$CMPSUCAP_{\ q,\ r,\ p,\ s}$	\$/Start	*Constraint Management Plan Startup Cap*—The CMP cap is the Resource Category Startup Offer Generic Cap (RCGSC) unless ERCOT has approved verifiable unit-specific Startup Costs for that Resource, in which case the CMP startup cap will be verifiable unit-specific Startup Cost determined as described in Section 5.6.1. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
q	None	A QSE.
r	None	A Generation Resource.
p	None	A Resource Node Settlement Point.
i	None	A 15-minute Settlement Interval.
h	None	An Operating Hour.
cold	None	A cold start

~~Variable~~	~~Unit~~	~~Definition~~
~~$CMPLOAL_{q,\ r,\ p,\ i}$~~	~~\$~~	~~*Constraint Management Plan attested losses*—The financial loss to the QSE due trip Off-Line of Resource following implementation of CMP or equivalent VDI as attested by the QSE in accordance with paragraph (1)(d) above.~~
~~$CMPEAMT_{q,\ r,\ p,\ i}$~~	~~\$~~	~~*Constraint Management Plan energy amount per QSE per Generation Resource*—The payment to QSE *q* during eligible hours of a trip offline from an ERCOT-issued CMP or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.~~
~~$SUPR_{q,\ r,\ s}$~~	~~\$/MWh~~	~~*Startup Price*—The Settlement price for Resource *r* represented by QSE *q* for the start *s*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$SUO_{q,\ p,\ r}$~~	~~\$/start~~	~~*Startup Offer per start*—Represents an offer for all costs incurred by Generation Resource r represented by QSE *q* in starting up and reaching the Resource's LSL for the start *s*. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train.~~

~~Variable~~	~~Unit~~	~~Definition~~
~~$SUCAP_{q, r, s}$~~	~~\$/start~~	~~*Startup Cap*—The amount used for AGR *r* or Resource *r* represented by QSE *q* for the start *s* as Startup Costs. The cap is the Resource Category Startup Offer Generic Cap (RCGSC) unless ERCOT has approved verifiable unit-specific Startup Costs for that Resource, in which case the startup cap is the scaled verifiable unit-specific Startup Cost for the AGR or the verifiable unit-specific Startup Cost for non-AGRs. The verifiable unit-specific Startup Cost will be determined as described in Section 5.6.1, Verifiable Costs, minus the average energy produced during the time period between breaker close and LSL multiplied by the heat rate proxy "H" multiplied by the appropriate Fuel Index Price (FIP), Fuel Oil Price (FOP) or solid fuel price, for AGR and non-AGR Resources. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$RTSPP_{p, i}$~~	~~\$/MWh~~	~~*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval *i*.~~
~~$MOC_{q, r, h}$~~	~~\$/MWh~~	~~*Mitigated Offer Cap per Resource*—The MOC for Resource *r* represented by QSE *q* for the eligible hour *h* at the HSL as submitted in the COP. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.~~
~~$RCGSC_{z}$~~	~~\$/Start~~	~~*Resource Category Generic Startup Cost*—The Resource Category Generic Startup Cost cap for the category of the Resource, according to Section 4.4.9.2.3, Startup Offer and Minimum-Energy Offer Generic Caps, for the Operating Day.~~
~~*q*~~	~~None~~	~~A QSE.~~
~~*r*~~	~~None~~	~~A Generation Resource.~~
~~*p*~~	~~None~~	~~A Resource Node Settlement Point.~~
~~*i*~~	~~None~~	~~A 15-minute Settlement Interval.~~

(8~~7~~) The total compensation to each QSE for a trip ~~o~~Off-L~~l~~ine due to ERCOT CMP or equivalent VDI for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{CMPCR\cancel{E}AMTQSETOT}_{q,\,i} = \cancel{\{}\sum_{r}\sum_{p} \mathbf{CMPCR\cancel{E}AMT}_{q,\,r,\,p,\,i}\ \cancel{\}\ /\ (\text{intervals of outage})}$$

The above variables are defined as follows:

Variable	Unit	Definition
CMPCR~~E~~AMT $_{q,\,r,\,p,\,i}$	\$	*Constraint Management Plan* Cost Recovery~~energy a~~*Amount per QSE per Generation Resource*—The payment to QSE *q* during eligible hours of a Resource~~for~~ trip O~~o~~ff-L~~l~~ine from an ERCOT-issued CMP unit trip or equivalent VDI for Generation Resource *r* at Settlement Point *p* for the 15-minute Settlement Interval *i*. For a combined cycle Resource, *r* is a Combined Cycle Train.

Variable	Unit	Definition
CMPCR~~E~~AMTQSETOT $_{q, i}$	$	*Constraint Management Plan Cost Recovery~~energy~~ ~~a~~Amount QSE ~~t~~Total per QSE*—The total of the cost recovery~~energy~~ payments to QSE *q* ~~as compensation for HDL overrides for this QSE~~ due to an ERCOT-issued CMP or equivalent VDI for the 15-minute Settlement Interval *i*.
q	none	A QSE.
r	none	A Generation Resource.
p	none	A Resource Node Settlement Point.
i	none	A 15-minute Settlement Interval.

6.6.3.10 Real-Time Constraint Management Plan Cost Recovery~~Energy~~ Charge

(1) ERCOT shall allocate to QSEs on an LRS basis the total amount of the payment specified in Section 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery~~Energy~~ Payment. The charge to each QSE for a given 15-minute Settlement Interval is calculated as follows:

$$\textbf{LACMPCREAMT}_{q,\,i} = (-1) * \textbf{CMPCREAMTTOT}_{i} * \textbf{LRS}_{q,\,i}$$

Where:

$$\text{CMPCREAMTTOT}_{i} = \sum_{q} \text{CMPCREAMTQSETOT}_{q,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
LACMPCR~~E~~AMT $_{q, i}$	$	*Load-Allocated Constraint Management Plan Cost Recovery~~energy~~ ~~a~~Amount per QSE*—The charge to QSE *q* for Constraint Management Plan Cost Recovery~~energy~~ ~~p~~Payment as identified in Section 6.6.3.9, for the 15-minute Settlement Interval *i*.
CMPCR~~E~~AMTTOT $_{i}$	$	*Constraint Management Plan Cost Recovery~~energy~~ ~~a~~Amount total*—The total of payments to all QSEs Constraint Management Plan Cost Recovery~~energy~~ ~~p~~Payments, for the 15-minute Settlement Interval *i*.
CMPCR~~E~~AMTQSETOT $_{q, i}$	$	*Constraint Management Plan Cost Recovery~~energy~~ ~~a~~Amount QSE total per QSE*—The total of the Constraint Management Plan Cost Recovery~~energy~~ ~~p~~Payments to QSE *q* due to an ERCOT-issued CMP or equivalent VDI~~as compensation for a Constraint Management Plan energy payment for this QSE~~ for the 15-minute Settlement Interval *i*.
LRS $_{q, i}$	none	*The Load Ratio Share* calculated for QSE *q* for the 15-minute Settlement Interval *i*. See Section 6.6.2.2, QSE Load Ratio Share for a 15-Minute Settlement Interval.
q	none	A QSE.
i	none	A 15-minute Settlement Interval.

6.6.3.11 Miscellaneous Invoice for Cost Recovery Payments and Charges for a Real-

Time Constraint Management Plan

(1) Each~~All~~ approved dispute~~s~~ shall be settled as described in Section 9.14.2, Notice of Dispute~~ERCOT shall issue one-time monthly miscellaneous Invoices using the most recent available Settlement data at the time the Invoices were issued.~~

(2) ERCOT shall issue a miscellaneous Invoice~~s~~ ~~on a monthly basis~~ to the QSE~~s~~ representing the Resource that has received a Constraint Management Plan payment, as described in Section 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery~~Energy~~ Payment.

(3) ERCOT shall issue a miscellaneous Invoice~~s~~ to the QSE representing Load based on the LRS~~on a monthly basis and allocate costs to the impacted QSEs~~ as described in Section 6.6.3.10, Real-Time Constraint Management Plan Cost Recovery~~Energy~~ Charge.

(4) ERCOT shall issue a one-time miscellaneous Invoice encompassing all Operating Days in each approved dispute using the most recent available Settlement data at the time the Invoices were issued. ~~The payment and allocation using a Miscellaneous Invoice will be done after the final settlement has occurred.~~

(54) ERCOT shall issue a Market Notice in conjunction with the issuance of miscellaneous Invoices for payments or charges for Real-Time Constraint Management Plan Settlement.

[NPRR1229: Delete Section 6.6.3.11 above upon system implementation.]

9.5.3 Real-Time Market Settlement Charge Types

Commented [CP1]: Please note NPRRs 1214 and 1235 also propose revisions to this section.

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

(j) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(k) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Charge;

(o) Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG);

(p) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;

(q) Section 6.6.5.1.1.1, Base Point Deviation Charge for Over Generation;

(r) Section 6.6.5.1.1.2, Base Point Deviation Charge for Under Generation;

(s) Section 6.6.5.2, IRR Generation Resource Base Point Deviation Charge;

(t) Section 6.6.5.4, Base Point Deviation Payment;

(u) Section 6.6.6.1, RMR Standby Payment;

(v) Section 6.6.6.2, RMR Payment for Energy;

(w) Section 6.6.6.3, RMR Adjustment Charge;

(x) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(y) Section 6.6.6.5, RMR Service Charge;

(z) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(aa) Paragraph (2) of Section 6.6.7.1, Voltage Support Service Payments;

(bb) Paragraph (4) of Section 6.6.7.1;

(cc) Section 6.6.7.2, Voltage Support Charge;

(dd) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(ee) Section 6.6.8.2, Black Start Capacity Charge;

(ff) Section 6.6.9.1, Payment for Emergency Power Increase Directed by ERCOT;

(gg) Section 6.6.9.2, Charge for Emergency Power Increases;

(hh) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(ii) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(jj) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;

(kk) Paragraph (1)(a) of Section 6.7.1, Payments for Ancillary Service Capacity Sold in a Supplemental Ancillary Services Market (SASM) or Reconfiguration Supplemental Ancillary Services Market (RSASM);

(ll) Paragraph (1)(b) of Section 6.7.1;

(mm) Paragraph (1)(c) of Section 6.7.1;

(nn) Paragraph (1)(d) of Section 6.7.1;

(oo) Paragraph (1)(e) of Section 6.7.1;

(pp) Paragraph (1)(a) of Section 6.7.2, Payments for Ancillary Service Capacity Assigned in Real-Time Operations;

(qq) Paragraph (1)(b) of Section 6.7.2;

(rr) Paragraph (1)(c) of Section 6.7.2;

(ss) Paragraph (1)(a) of Section 6.7.2.1, Charges for Infeasible Ancillary Service Capacity Due to Transmission Constraints;

(tt) Paragraph (1)(b) of Section 6.7.2.1;

(uu) Paragraph (1)(c) of Section 6.7.2.1;

(vv) Paragraph (1)(d) of Section 6.7.2.1;

(ww) Paragraph (1)(e) of Section 6.7.2.1;

(xx) Paragraph (1)(a) of Section 6.7.3, Charges for Ancillary Service Capacity Replaced Due to Failure to Provide;

(yy) Paragraph (1)(b) of Section 6.7.3;

(zz) Paragraph (1)(c) of Section 6.7.3;

(aaa) Paragraph (1)(d) of Section 6.7.3;

(bbb) Paragraph (1)(e) of Section 6.7.3;

(ccc) Paragraph (2) of Section 6.7.4, Adjustments to Cost Allocations for Ancillary Services Procurement;

(ddd) Paragraph (3) of Section 6.7.4;

(eee) Paragraph (4) of Section 6.7.4;

(fff) Paragraph (5) of Section 6.7.4;

(ggg) Paragraph (6) of Section 6.7.4;

(hhh) Paragraph (7) of Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge (Real-Time Ancillary Service Imbalance Amount);

(iii) Paragraph (7) of Section 6.7.5, (Real-Time Reliability Deployment Ancillary Service Imbalance Amount);

(jjj) Paragraph (8) of Section 6.7.5, (Real-Time RUC Ancillary Service Reserve Amount);

(kkk) Paragraph (8) of Section 6.7.5, (Real-Time Reliability Deployment RUC Ancillary Service Reserve Amount);

(lll) Section 6.7.6, Real-Time Ancillary Service Imbalance Revenue Neutrality Allocation (Load-Allocated Ancillary Service Imbalance Revenue Neutrality Amount);

(mmm) Section 6.7.6, (Load-Allocated Reliability Deployment Ancillary Service Imbalance Revenue Neutrality Amount);

(nnn) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and

(ooo) Section 9.16.1, ERCOT System Administration Fee.

[NPRR841, NPRR885, NPRR963, NPRR995, NPRR1012, NPRR1014, and NPRR1216: Replace applicable portions of paragraph (1) above with the following upon system implementation for NPRR841, NPRR885, NPRR963, NPRR995, NPRR1014, or NPRR1216 (Phase 2); or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]

(1) ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for each RTM Settlement charge and payment. The RTM Settlement "Charge Types" are:

(a) Section 5.7.1, RUC Make-Whole Payment;

(b) Section 5.7.2, RUC Clawback Charge;

(c) Section 5.7.3, Payment When ERCOT Decommits a QSE-Committed Resource;

(d) Section 5.7.4.1, RUC Capacity-Short Charge;

(e) Section 5.7.4.2, RUC Make-Whole Uplift Charge;

(f) Section 5.7.5, RUC Clawback Payment;

(g) Section 5.7.6, RUC Decommitment Charge;

(h) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node;

(i) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone;

(j) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(k) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(l) Section 6.6.3.5, Real-Time Payment for a Block Load Transfer Point;

(m) Section 6.6.3.6, Real-Time High Dispatch Limit Override Energy Payment;

(n) Section 6.6.3.7, Real-Time High Dispatch Limit Override Energy Charge;

(o) Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS);

(p) Section 6.6.3.9, Real-Time Constraint Management Plan Cost Recovery Payment;

(q) Section 6.6.3.10, Real-Time Constraint Management Plan Cost Recovery Charge;

(r~~p~~) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules;

(s~~q~~) Section 6.6.5.2, Set Point Deviation Charge for Over Generation;

(t~~r~~) Section 6.6.5.2.1, Set Point Deviation Charge for Under Generation;

(u~~s~~) Section 6.6.5.3, Controllable Load Resource Set Point Deviation Charge for Over Consumption;

(v~~t~~) Section 6.6.5.3.1, Controllable Load Resource Set Point Deviation Charge for Under Consumption;

(w~~u~~) Section 6.6.5.4, IRR Generation Resource Set Point Deviation Charge;

(x~~v~~) Section 6.6.5.4, Set Point Deviation Payment;

(y~~w~~) Section 6.6.5.5, Energy Storage Resource Set Point Deviation Charge for Over Performance;

(z~~x~~) Section 6.6.5.5.1, Energy Storage Resource Set Point Deviation Charge for Under Performance;

(aa~~y~~) Section 6.6.6.1, RMR Standby Payment;

(bb~~z~~) Section 6.6.6.2, RMR Payment for Energy;

(cc~~aa~~) Section 6.6.6.3, RMR Adjustment Charge;

(dd~~bb~~) Section 6.6.6.4, RMR Charge for Unexcused Misconduct;

(ee~~cc~~) Section 6.6.6.5, RMR Service Charge;

(ff~~dd~~) Section 6.6.6.6, Method for Reconciling RMR Actual Eligible Costs, RMR and MRA Contributed Capital Expenditures, and Miscellaneous RMR Incurred Expenses;

(gg~~ee~~) Section 6.6.6.7, MRA Standby Payment;

(hh~~ff~~) Section 6.6.6.8, MRA Contributed Capital Expenditures Payment;

(ii~~gg~~) Section 6.6.6.9, MRA Payment for Deployment Event;

(jj~~hh~~) Section 6.6.6.10, MRA Variable Payment for Deployment;

(kk~~ii~~) Section 6.6.6.11, MRA Charge for Unexcused Misconduct;

(ll~~jj~~) Section 6.6.6.12, MRA Service Charge;

(mm~~kk~~) Paragraph (3) of Section 6.6.7.1, Voltage Support Service Payments;

(nn~~ll~~) Paragraph (5) of Section 6.6.7.1;

(oo~~mm~~) Section 6.6.7.2, Voltage Support Charge;

(pp~~nn~~) Section 6.6.8.1, Black Start Hourly Standby Fee Payment;

(qq~~oo~~) Section 6.6.8.2, Black Start Capacity Charge;

(rr~~pp~~) Section 6.6.9.1, Payment for Emergency Operations Settlement;

(ss~~qq~~) Section 6.6.9.2, Charge for Emergency Operations Settlement;

(tt~~rr~~) Section 6.6.10, Real-Time Revenue Neutrality Allocation;

(uu~~ss~~) Section 6.6.11.1, Emergency Response Service Capacity Payments;

(vv~~tt~~) Section 6.6.11.2, Emergency Response Service Capacity Charge;

(ww~~uu~~) Section 6.6.14.2, Firm Fuel Supply Service Hourly Standby Fee Payment and Fuel Replacement Cost Recovery;

(xx~~vv~~) Section 6.6.14.3, Firm Fuel Supply Service Capacity Charge;

(yy~~ww~~) Section 6.7.4, Real-Time Settlement for Updated Day-Ahead Market Ancillary Service Obligations;

(zz~~xx~~) Section 6.7.5.2, Regulation Up Service Payments and Charges;

(aaa~~yy~~) Section 6.7.5.3, Regulation Down Service Payments and Charges;

(bbb~~zz~~) Section 6.7.5.4, Responsive Reserve Payments and Charges;

(ccc~~aaa~~) Section 6.7.5.5, Non-Spinning Reserve Service Payments and Charges;

(ddd~~bbb~~) Section 6.7.5.6, ERCOT Contingency Reserve Service Payments and Charges;

(eee~~ccc~~) Section 6.7.5.7, Real-Time Derated Ancillary Service Capability Payment;

(fff~~ddd~~) Section 6.7.5.8, Real-Time Derated Ancillary Service Capability Charge;

(ggg~~eee~~) Section 6.7.6, Real-Time Ancillary Service Revenue Neutrality Allocation;

(hhh~~fff~~) Section 6.8.2, Recovery of Operating Losses During an LCAP or ECAP Effective Period;

(iii~~ggg~~) Section 6.8.3, Charges for Operating Losses During an LCAP or ECAP Effective Period;

(jjj~~hhh~~) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time; and

(kkk~~iii~~) Section 9.16.1, ERCOT System Administration Fee.

(2) In the event that ERCOT is unable to execute the Day-Ahead Market (DAM), ERCOT shall provide, on each RTM Settlement Statement, the dollar amount for the following RTM Congestion Revenue Right (CRR) Settlement charges and payments:

(a) Section 7.9.2.4, Payments for FGRs in Real-Time; and

(b) Section 7.9.2.5, Payments and Charges for PTP Obligations with Refund in Real-Time.

ERCOT Impact Analysis Report

NPRR Number	1229	NPRR Title	Real-Time Constraint Management Plan Cost Recovery Payment
Impact Analysis Date	April 8, 2025		
Estimated Cost/Budgetary Impact	Between $100K and $200K		
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: 8 to 10 months		
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: • Market Settlements 98% • Retail Operations 2%		
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	<u>1238</u>	NPRR Title	**Voluntary Registration of Loads with Curtailable Load Capabilities**

Date of Decision	June 24, 2025
Action	Recommended Approval
Timeline	Normal
Estimated Impacts	Cost/Budgetary: Between $700k and $1.0M Project Duration: 10 to 14 months
Proposed Effective Date	Upon system implementation
Priority and Rank Assigned	Priority – 2026; Rank – 4535
Nodal Protocol Sections Requiring Revision	2.1, Definitions 2.2, Acronyms and Abbreviations 6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder 6.5.9.4.1, General Procedures Prior to EEA Operations 16.20, Designation of a Qualified Scheduling Entity by a Voluntary Early Curtailment Load (new) 23, Form T, Voluntary Early Curtailment Load Designation Form (new)
Related Documents Requiring Revision/Related Revision Requests	Nodal Operating Guide Revision Request (NOGRR) 265, Related to NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities
Revision Description	This Nodal Protocol Revision Request (NPRR) introduces a new category of Voluntary Early Curtailment Load (VECL) and establishes a process by which Loads may operate as a VECL so that they can be accounted for differently in Load shed tables than other Loads.
Reason for Revision	☐ <u>Strategic Plan</u> Objective 1 – Be an industry leader for grid reliability and resilience ☐ <u>Strategic Plan</u> 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 improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR establishes a process by which Loads may inform ERCOT that the Load consumer is willing to curtail in the event of a Physical Responsive Capability (PRC) shortfall as defined in Section 6.5.9.4.1 in order to help utilities and ERCOT properly account for Load shed obligations. This process is necessary so that utilities with large Loads that will be Off-Line during emergency operations don't impact that utility's expected Load shed obligations. For example, a utility that typically has 200 MW of Demand may have a new Customer that is adding 800 MW of Demand. If they are expected to shed 5% of their Load during an emergency, then the Load shed obligation would increase from 10 MW to 50 MW. If the new 800 MW customer will actually be Off-Line, then it should have no incremental impact on the utility's Load shed obligation.
PRS Decision	On 7/18/24, PRS voted unanimously to table NPRR1238 and refer the issue to ROS and WMS. All Market Segments participated in the vote. On 3/12/25, PRS voted to recommend approval of NPRR1238 as amended by the 2/25/25 Oncor comments. There was one opposing vote from the Independent Retail Electric Provider (IREP) (Just Energy) Market Segment, and one abstention from the Consumer (Occidental) Market Segment. All Market Segments participated in the vote. On 4/9/25, PRS voted unanimously to table NPRR1238. All Market Segments participated in the vote. On 5/14/25, PRS voted to endorse and forward to TAC the 4/9/25 PRS Report as amended by the 5/7/25 ERCOT comments and 5/13/25 Impact Analysis for NPRR1238 with a recommended priority of 2026 and rank of 4535. There were two abstentions from the

Board Report

	Consumer (Occidental) and Independent Generator (Eolian) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 7/18/24, the sponsor provided an overview of NPRR1238 and confirmed that there was no longer a need for urgency. Participants requested that NPRR1238 be tabled and referred to ROS and WMS for further review by Operations Working Group (OWG) and Wholesale Market Working Group (WMWG), respectively. On 3/12/25, participants reviewed the 2/25/25 Oncor comments. The sponsor cited continued economic and compliance risk while NPRR1238 remains pending; requested that PRS recommend approval in effort to reach the May 28, 2025 TAC meeting; and expressed willingness to withdraw NPRR1238 should Senate Bill 6 (SB6) resolve the compliance issue, once finalized. Some participants debated SB6's anticipated effect on NPRR1238 and questioned the merit of spending limited ERCOT resources developing an Impact Analysis when SB6 might ultimately negate NPRR1238's concept. On 4/9/25, PRS reviewed the 3/31/25 ERCOT comments. Some participants expressed concern that further delay will prevent NPRR1238 from being approved in time for the 2025 winter season. On 5/14/25, PRS reviewed the 5/7/25 ERCOT comments and 5/13/25 Impact Analysis. The sponsor emphasized shared compliance risks if NPRR1238 is not approved and cited issues remaining in SB6's development. Participants discussed the cost benefit of NPRR1238; and whether it should be tabled pending SB6 resolution. The priority and rank and continued evaluation of NPRR1238's impacts were discussed.
TAC Decision	On 5/28/25, TAC voted unanimously to table NPRR1238. All Market Segments participated in the vote. On 6/12/25, TAC voted unanimously to recommend approval of NPRR1238 as recommended by PRS in the 5/14/25 PRS Report as amended by the 6/5/25 TIEC comments and the 5/27/25 Revised Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 5/28/25, TAC reviewed the items below. ERCOT cited potential discrepancy between NPRR1238 and SB6 language regarding ERCOT's right to curtail large Loads ahead of Energy Emergency Alert (EEA) and stated their preference that TAC not recommend approval of NPRR1238 to the ERCOT Board until SB6 language is finalized per procedural norms. PUCT Staff expressed support of the 5/27/25 ERCOT comments. Participants acknowledged likely market impacts pending finalization of SB6 large Load language. Some participants debated whether NPRR1238 applies exclusively to

	flexible loads, citing a need for explicit language settling the fact. The sponsor reiterated urgency, requesting to implement NPRR1238 in time for 2026 summer season. The TAC Chair committed to holding a Special TAC meeting in order to consider latest SB6 language and determine further NPRR1238 action ahead of the June 24, 2025 ERCOT Board meeting. On 6/12/25, TAC reviewed the 6/5/25 TIEC comments, 6/10/25 GSEC comments, and the 6/11/25 ERCOT comments.
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 6/24/25, the ERCOT Board voted unanimously to recommend approval of NPRR1238 as recommended by the 6/12/25 TAC Report and the 6/13/25 Revised Impact Analysis.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1238 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 NPRR1238.
ERCOT Opinion	ERCOT supports approval of NPRR1238.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1238 and believes that it provides improvements by introducing a new category of VECL and establishing a process by which Loads may operate as a VECL so that they can be accounted for differently in Load shed tables than other Loads.

Sponsor	
Name	Joe Dan Wilson
E-mail Address	jwilson@gsec.coop

Board Report

Company	GSEC
Phone Number	806-349-5210
Cell Number	806-340-1214
Market Segment	Cooperative

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**
ROS 071124	Requested PRS table NPRR1238 for further review by OWG
ROS 080124	Requested PRS continue to table NPRR1238 for further review by the OWG
WMS 080724	Requested PRS continue to table NPRR1238 for further review by the WMWG
Oncor 081424	Proposed edits regarding the Transmission Operator (TO) roles associated with VECLs
ERCOT Steel Mills 103124	Proposed edits excluding Emergency Response Service (ERS) providers from the definition of VECL as ERS providers are deployed separately in other sections of NPRR1238
ERCOT 020625	Proposed clarifying edits to NPRR1238 including removal and addition of various requirements
WMS 020725	Advised PRS that WMS has concluded discussion of NPRR1238 and has no recommendation at this time
Oncor 022525	Added TO as an entity from which written consent should be obtained if a Customer seeks to terminate its ECL registration
ROS 030625	Endorsed NPRR1238 as amended by the 2/25/25 Oncor comments
ERCOT 031125	Requested that the PRS table NPRR1238 pending the Texas Legislature's consideration of SB6

Board Report

ERCOT 033125	Proposed an alternative schedule for the development of an Impact Analysis for NPRR1238 prior to the May 14, 2025 PRS meeting
ERCOT 050725	Proposed edits to remove language requiring ERCOT to notify TOs of the ECL deployment via an Extensible Markup Language (XML) message; and replaced language to clarify telemetry requirement
ERCOT 052725	Requested that TAC table NPRR1238 until SB6 language has been finalized
TIEC 060525	Proposed edits clarifying that the registration of loads with curtailable load capabilities must be voluntary
GSEC 061025	Expressed support for the 6/5/25 TIEC comments
ERCOT 061125	Expressed support for NPRR1238 upon identifying anticipated use cases not appearing to raise a risk of conflict with the requirements of SB6; emphasized, in response to the 6/5/25 TIEC comments, that, while registration as an ECL (or VECL) may be voluntary, the performance requirements under the Protocols for customers that do elect such registration would not be voluntary

Market Rules Notes

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

- NPRR1219, Methodology Revisions and New Definitions for the Report on Capacity, Demand and Reserves in the ERCOT Region (CDR) (incorporated 10/1/24)
  - Section 3.2.6.2.1
  - Section 6.5.9.4.1
- NPRR1245, Additional Clarifying Revisions to Real-Time Co-Optimization (incorporated 2/1/25)
  - Section 6.5.7.3.1

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

- NPRR1214, Reliability Deployment Price Adder Fix to Provide Locational Price Signals, Reduce Uplift and Risk
  - Section 6.5.7.3.1
- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
  - Section 6.5.7.3.1
- NPRR1290, Gap Resolutions and Clarifications for the Implementation of RTC+B

Board Report

- Section 6.5.7.3.1

Proposed Protocol Language Revision

2.1 DEFINITIONS

~~Voluntary~~ Voluntary Early Curtailment Load (~~V~~VECL)

A Load interconnected to the ERCOT System ~~at transmission voltage in which the Customer~~ that has been registered with ERCOT as a~~n~~ VECL ~~that the Load will~~ for the purpose of curtailing in response to an ERCOT instruction when necessary to maintain system reliability. ~~The Load does not receive instructions from Security-Constrained Economic Dispatch (SCED) and is not a Load Resource or is registered as an Emergency Response Service (ERS) provider.~~

2.2 ACRONYMS AND ABBREVIATIONS

~~V~~VECL ~~Voluntary~~ Voluntary Early Curtailment Load

6.5.7.3.1 Determination of Real-Time On-Line Reliability Deployment Price Adder

Commented [JT1]: Please note NPRRs 1214 and 1235 also propose revisions to this section.

(1) The following categories of reliability deployments are considered in the determination of the Real-Time On-Line Reliability Deployment Price Adder:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than CLRs;

(d) Deployed ERS;

(e) Real-Time DC Tie imports during an EEA where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) Real-Time DC Tie exports to address emergency conditions in the receiving electric grid;

(g) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(h) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid;~~ and~~

(i) Deployed ~~Voluntary~~ Voluntary Early Curtailment Load (~~V~~VECL), as described in ~~paragraph (2) of~~ Section 6.5.9.4.1, General Procedures Prior to EEA Operations; and

(j~~i~~) ERCOT-directed firm Load shed during EEA Level 3, as described in paragraph (3) of Section 6.5.9.4.2, EEA Levels.

(2) The Real-Time On-Line Reliability Deployment Price Adder is an estimation of the impact to energy prices due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, after the two-step SCED process and also after the Real-Time On-Line Reserve Price Adder and Real-Time Off-Line Reserve Price Adder have been determined, the Real-Time On-Line Reliability Deployment Price Adder is determined as follows:

(a) For RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line, set the LSL, LASL, and LDL to zero.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity, set the LSL, LASL, and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes * SCED Down Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes*SCED Up Ramp Rate), or HASL.

(d) For all CLRs excluding ones with a telemetered status of OUTL:

(i) Set LDL to the greater of Aggregated Resource Output - (60 minutes * SCED Up Ramp Rate), or LASL; and

(ii) Set HDL to the lesser of Aggregated Resource Output + (60 minutes*SCED Down Ramp Rate), or HASL.

(e) Add the deployed MW from Load Resources that are not CLRs and that are providing RRS or ECRS to GTBD linearly ramped over the ten-minute ramp period and add the deployed MW from Load Resources that are not CLRs providing Non-Spin to GTBD linearly ramped over the 30-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the restoration period length and amount of MW added to GTBD during the restoration period will be determined by validated telemetry and the type of Ancillary Service deployed from the Resource. The TAC shall review the validity of the prices for the bid curve at least annually.

(f) Add the deployed MW from ~~V~~VECL to GTBD linearly ramped over a 30-minute ramp period. The amount of deployed MW is calculated from the applicable deployment instructions in XML messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of ~~V~~VECL deployed and a price/quantity pair of $700/MWh for the last MW of ~~V~~VECL deployed in each SCED execution. After recall instruction, GTBD shall be adjusted to reflect restoration on a linear curve over a one-hour restoration period.

(g~~f~~) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours").

The above parameter is defined as follows:

Parameter	Unit	Current Value*
RHours	Hours	4.5
* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(h~~g~~) Add the MW from Real-Time DC Tie imports during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(i~~h~~) Subtract the MW from Real-Time DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(j~~i~~) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(k~~j~~) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(l~~k~~) Perform a SCED with changes to the inputs in items (a) through (~~j~~k) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(m~~l~~) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(n~~m~~) Perform a SCED with the changes to the inputs in items (a) through (k~~j~~) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy Offer Curves.

(o~~n~~) Determine the positive difference between the System Lambda from item (n~~m~~) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(p~~o~~) Determine the amount given by the Value of Lost Load (VOLL) minus the sum of the System Lambda of the second step in the two step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder.

(q~~p~~) The Real-Time On-Line Reliability Deployment Price Adder is the minimum of items (~~n~~o) and (p~~o~~) above except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time On-Line Reliability Deployment Price Adder is the VOLL minus the sum of the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder. Once ERCOT is no longer directing firm Load shed, as described above, the Real-Time On-Line Reliability Deployment Price Adder will again be set as the minimum of items (o~~n~~) and (p~~o~~) above.

[NPRR904, NPRR1006, NPRR1010, NPRR1014, NPRR1091, NPRR1105, NPRR1188, and NPRR1245: Replace applicable portions of Section 6.5.7.3.1 above with the following upon

system implementation for NPRR904, NPRR1006, NPRR1014, NPRR1091, NPRR1105, or NPRR1188; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1245:]

6.5.7.3.1 Determination of Real-Time Reliability Deployment Price Adder

(1) The following categories of reliability deployments are considered in the determination of the Real-Time Reliability Deployment Price Adder for Energy, and the Real-Time Reliability Deployment Price Adders for Ancillary Services:

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (14) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (4) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than CLRs;

(d) Deployed ERS;

(e) ERCOT-directed DC Tie imports during an EEA or transmission emergency where the total adjustment shall not exceed 1,250 MW in a single interval;

(f) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;

(g) ERCOT-directed curtailment of DC Tie imports below the higher of DC Tie advisory import limit as of 0600 in the Day-Ahead or subsequent advisory import limit due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT where the total adjustment shall not exceed 1,250 MW in a single interval;

(h) ERCOT-directed DC Tie exports to address emergency conditions in the receiving electric grid where the total adjustment shall not exceed 1,250 MW in a single interval;

(i) ERCOT-directed curtailment of DC Tie exports below the DC Tie advisory export limit as of 0600 in the Day-Ahead or subsequent advisory export limit during EEA, a transmission emergency, or to address local transmission system limitations where the total adjustment shall not exceed 1,250 MW in a single interval;

(j) Energy delivered to ERCOT through registered Block Load Transfers (BLTs) during an EEA;

(k) Energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid;

(l) ERCOT-directed deployment of TDSP standard offer Load management programs;

(m) ERCOT-directed deployment of distribution voltage reduction measures;

(n) ERCOT-directed deployment of Off-Line Non-Spin; ~~and~~

(o) ERCOT-directed firm Load shed during EEA Level 3, as described in paragraph (3) of Section 6.5.9.4.2, EEA Levels~~.~~; and

(~~o~~p) Deployed ~~Voluntary~~ Voluntary Early Curtailment Load (~~V~~VECL) as described in ~~paragraph (2) of~~ Section 6.5.9.4.1, General Procedures Prior to EEA Operations.

(2) The Real-Time Reliability Deployment Price Adder for Energy, and Real-Time Reliability Deployment Price Adders for Ancillary Services are estimations of the impact to energy prices and Real-Time MCPCs due to the above categories of reliability deployments. For intervals where there are reliability deployments as described in paragraph (1) above, the Real-Time Reliability Deployment Price Adder for Energy and Real-Time Reliability Deployment Price Adders for Ancillary Services are determined as follows:

(a) For Off-Line Non-Spin Resources that are brought On-Line by ERCOT deployment instruction, RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line:

(i) Set the LSL and LDL to zero;

(ii) Remove all Ancillary Service Offers; and

(iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the power balance penalty price for all capacity between 0 MW and the HSL of the Resource.

(b) Notwithstanding item (a) above, for RUC-committed Combined Cycle Generation Resources with a telemetered Resource Status of ONRUC that were instructed by ERCOT to transition to a different configuration to provide additional capacity:

(i) Set the LSL and LDL equal to the minimum of their current value and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction;

(ii) Set the maximum Ancillary Service capabilities of the Resource equal to the minimum of their current value and COP Ancillary Service capabilities of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction; and

(iii) For the first step of SCED, administratively set the Energy Offer Curve for the Resource at a value equal to the power balance penalty price for the additional capacity of the Resource, defined as the positive difference between the Resource's current telemetered HSL and the COP HSL of the QSE-committed configuration for the RUC hour at the snapshot time of the RUC instruction.

(c) For all other Generation Resources excluding ones with a telemetered status of ONRUC, ONTEST, STARTUP, SHUTDOWN, and also excluding RMR Resources that are On-Line and excluding Generation Resources with a telemetered output less than 95% of LSL:

(i) If the Generation Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the Generation Resource SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(d) For all On-Line ESRs:

(i) If the ESR SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the ESR SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(e) For all CLRs excluding ones with a telemetered status of OUTL, ONTEST, or ONHOLD:

(i) If the CLR SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes * Normal Ramp Rate down), or LSL; and

(ii) If the CLR SCED Base Point is not at HDL, set HDL to the lesser of Aggregated Resource Output + (60 minutes * Normal Ramp Rate up), or HSL.

(f) Add the deployed MW from Load Resources that are not CLRs and that are providing RRS or ECRS to GTBD linearly ramped over the ten-minute ramp period and add the deployed MW from Load Resources that are not CLRs providing Non-Spin to GTBD linearly ramped over the 30-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the restoration period length and amount of MW added to GTBD during the restoration period will be determined by validated telemetry and the type of Ancillary Service deployed from the Resource. The TAC shall review the validity of the prices for the bid curve at least annually.

(g) Add the deployed MW from ~~V~~VECL to GTBD linearly ramped over a 30-minute ramp period. The amount of deployed MW is calculated from the applicable deployment instructions in XML messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of ~~V~~VECL deployed and a price/quantity pair of $700/MWh for the last MW of ~~V~~VECL deployed in each SCED execution. After recall instruction, GTBD shall be adjusted to reflect restoration on a linear curve over a one-hour restoration period.

(h~~g~~) Add the deployed MW from ERS to GTBD. The amount of deployed MW is determined from the XML messages and ERS contracted capacities for the ERS Time Periods when ERS is deployed. After recall, an approximation of the amount of un-restored ERS shall be used. After ERCOT recalls each group, GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours").

The above parameter is defined as follows:

Parameter	Unit	Current Value*
RHours	Hours	4.5
* Changes to the current value of the parameter(s) referenced in this table above may be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(i~~h~~) Add the MW from DC Tie imports during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by

ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(j~~i~~) Add the MW from DC Tie export curtailments during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator. The MW added to GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for exports on that tie as of 0600 in the Day-Ahead or subsequent advisory export limit minus the aggregate export on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.

(k~~j~~) Subtract the MW from DC Tie exports to address emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(l~~k~~) Subtract the MW from DC Tie import curtailments to address local transmission system limitations or emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator. The MW subtracted from GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for imports on that tie as of 0600 in the Day-Ahead or subsequent advisory import limit minus the aggregate import on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.

(m~~l~~) Add the MW from energy delivered to ERCOT through registered BLTs during an EEA to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

(n~~m~~) Subtract the MW from energy delivered from ERCOT to another power pool through registered BLTs during emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator.

(o~~n~~) Add the deployed MWs from TDSP standard offer Load management programs to GTBD, if ERCOT instructs TDSPs to deploy their standard offer Load management programs. The amount of deployed MW is the value ERCOT provided for all TDSP standard offer Load management programs in the most current May Report on Capacity, Demand and Reserves in the ERCOT Region (CDR), unless modified as specified in this paragraph. If ERCOT is informed that all or a portion of a TDSP's standard offer Load management program has been fully exhausted, or has been expanded as the result of a Public Utility Commission of Texas (PUCT) proceeding, ERCOT will remove the associated MW value of any exhausted capacity from the amount of deployed MW or, in the case of an expansion, ERCOT will request an updated MW value from the relevant TDSPs to use in place of the May CDR in the ERCOT Region value for that year. The initial value ERCOT will use for deployed MW under this paragraph for each calendar year, as well as any subsequent changes to this value, will be communicated to Market Participants in a Market Notice. After recall, an approximation of the amount of un-restored TDSP standard offer Load management programs shall be used. GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours") defined by item (h~~g~~) above.

(p~~o~~) Perform a SCED with changes to the inputs in items (a) through (n~~m~~) above, considering only Competitive Constraints and the non-mitigated Energy Offer Curves.

(q~~p~~) Perform mitigation on the submitted Energy Offer Curves using the LMPs from the previous step as the reference LMP.

(r~~q~~) Perform a SCED with the changes to the inputs in items (a) through (n~~m~~) above, considering both Competitive and Non-Competitive Constraints and the mitigated Energy Offer Curves.

(s~~r~~) The Real-Time Reliability Deployment Price Adder for Energy is equal to the positive difference between the System Lambda from item (r~~q~~) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch, except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time Reliability Deployment Price Adder for Energy is the VOLL used to determine the Ancillary Service Demand Curves (ASDCs) for the Real-Time Market (RTM) minus the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3.

(t~~s~~) For each individual Ancillary Service, the Real-Time Reliability Deployment Price Adder for Ancillary Service is equal to the positive difference between the MCPC for that Ancillary Service from item (r~~q~~) above and the MCPC for that Ancillary Service, except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time Reliability Deployment Price Adder for Ancillary Service is the maximum value on the ASDC for the Ancillary Service minus the MCPC for that Ancillary Service.

6.5.9.4.1 General Procedures Prior to EEA Operations

(1) Prior to declaring EEA Level 1 detailed in Section 6.5.9.4.2, EEA Levels, ERCOT may perform the following operations consistent with Good Utility Practice:

(a) Provide Dispatch Instructions to QSEs for specific Resources to operate at an Emergency Base Point to maximize Resource deployment so as to increase PRC levels on other Resources;

(b) Commit specific available Resources as necessary that can respond in the timeframe of the emergency. Such commitments will be settled using the HRUC process;

(c) Start RMR Units available in the time frame of the emergency. RMR Units should be loaded to full capability;

(d) Utilize available Resources providing RRS, ECRS, and Non-Spin services as required;

(e) Instruct TSPs and DSPs or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures if ERCOT determines that the implementation of these measures could help avoid entering into EEA and ERCOT does not expect to need to use these measures to reduce the amount of Load shedding that may be needed in EEA Level 3. A TSP, DSP, or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability; and

(f) ERCOT shall use the PRC and system frequency to determine the appropriate Emergency Notice and EEA levels.

~~(2) A Load that is willing to curtail during any shortfall described in this Section, subject to an agreement with its QSE, interconnecting TO, and interconnecting TDSP(s), shall be registered by the QSE as a VECL pursuant to Section 23, Form T, Qualified Scheduling Entity, Transmission Operator, and Transmission and/or Distribution Service Provider(s) Acknowledgment of Designation for Customer with Large Load.~~

(2~~3~~) When PRC falls below 3,100 MW and is not projected to be recovered above 3,100 MW within 30 minutes following the deployment of Non-Spin, ERCOT may deploy some or all Voluntary Early Curtailment Loads (~~V~~VECLs) via an Extensible Markup Language (XML) message~~in 100 MW blocks allocated to QSEs~~, as described in Nodal Operating Guide Section 4.5.3.4, Qualified Scheduling Entity ~~V~~VECL Load reduction~~Shed~~