(i) The interval Load of the ERS Load was less than 95% of its contracted ERS MW capacity;

(ii) Required metered interval data was not provided to ERCOT by the time ERCOT calculated availability for one or more sites in the ERS Resource.

(b) Otherwise, the ERS Load will be considered available for that 15-minute interval. The ERSAF will be the ratio of the number of 15-minute intervals the ERS Load was available during the ERS Time Period divided by the total number of 15-minute intervals in the ERS Time Period.

(c) Notwithstanding the foregoing, in determining the ERSAF, ERCOT will exclude from the calculation the following contracted intervals:

(i) Any 15-minute interval in which the ERS Load was deployed during an ERS deployment event or unannounced test, including intervals that begin during the ten-hour ERS recovery period following the issuance of the recall instruction; and

(ii) Any 15-minute interval following an ERS deployment resulting in exhaustion of the ERS Load's obligation in an ERS Contract Period.

(2) For an ERS Load assigned to the alternate baseline, ERCOT will calculate its ERSAF for an ERS Time Period using the following formula:

$$\mathbf{ERSAF}_{\,qce(tp)d} = \mathbf{MIN\ (1,\ (AV}_{\,qce(tp)d}\ /\ \mathbf{(OFFERMW}_{\,qce(tp)d})))$$

The above variables are defined as follows:

Variable	Unit	Description
AV *qce(tp)d*	MW	Average MW Load, calculated as the average of the actual interval MW values or the MW values determined in accordance with paragraphs (a), (b), and (c) below, per 15-minute interval for an ERS Load in a contracted ERS Time Period per ERS service type *d*, excluding declared maximum base Load.
OFFERMW *qce(tp)d*	MW	An ERS Load's contracted capacity for an ERS Time Period, per ERS service type *d*, applicable to either competitively procured or self-provided ERS.
ERSAF *qce(tp)d*	None	Availability factor for an ERS Load for an ERS Time Period per ERS service type *d*.
q	None	A QSE.
c	None	ERS Contract Period.
e	None	An ERS Load.
tp	None	ERS Time Period.
d	None	ERS service type (Weather-Sensitive ERS-10, Non-Weather-Sensitive ERS-10, Weather -Sensitive ERS-30, or Non-Weather-Sensitive ERS-30).

(a) If the ERS Load is co-located with an ERS Generator and the QSE has opted for separate evaluation, its Load, for purposes of availability calculations, shall be determined as specified in paragraph (3)(c) of Section 8.1.3.1.2, Performance Evaluation for Emergency Response Service Generators.

(b) For purposes of calculating availability, the interval MW value will be deemed to be equal to the declared maximum base Load if the following condition is met:

(i) Required metered interval data was not provided to ERCOT by the time ERCOT calculated availability for one or more sites in the ERS Resource.

(c) For purposes of calculating availability, ERCOT shall exclude from the average any 15-minute interval meeting one or more of the following descriptions:

(i) Any 15-minute interval in which the ERS Load was deployed during an ERS deployment event or unannounced test, including intervals that begin during the ten-hour ERS recovery period following the issuance of the recall instruction; or

(ii) Any 15-minute interval following the ERS deployment resulting in exhaustion of the ERS Load's obligation in an ERS Contract Period.

(3) A Weather-Sensitive ERS Load shall always have its availability factor for an ERS Contract Period set to 1.0 and its availability settlement weighting factor (ERSAFWT) set to zero.

8.1.3.1.3.2 Time Period Availability Calculations for Emergency Response Service Generators

(1) ERCOT shall evaluate the availability of an ERS Generator by using data from 15-minute interval metering dedicated to the ERS Generator.

(2) ERCOT will calculate an ERSAF using interval meter readings for an ERS Generator for each committed ERS Time Period as the ratio of the number of 15-minute intervals the ERS Generator was available in the ERS Time Period divided by the total number of obligated 15-minute intervals in the ERS Time Period. ERS Generators are considered available for any 15-minute interval except the following:

(a) An ERS Generator that is not co-located with an ERS Load will be considered unavailable for all 15-minute intervals that are part of an unsuccessful unannounced ERCOT test or event, as well as any subsequent intervals following the end of the test or event up to the interval immediately preceding the first full 15-minute interval for which the ERS Generator injects energy to the ERCOT System at a level greater than or equal to the sum of its injection capacity and obligation at the time of the test or event. The success or lack of success of an unannounced ERCOT test or event is determined by the criteria specified in Section 8.1.3.2, Testing of Emergency Response Service Resources.

(b) An ERS Generator that is co-located with an ERS Load and is being separately evaluated from the ERS Load will be considered unavailable for all 15-minute intervals that are part of an unsuccessful unannounced ERCOT test or event, as well as any subsequent intervals following the end of the test up to the interval immediately preceding the first full 15-minute interval for which the ERS Generator's output energy is greater than or equal to the sum of its injection capacity and obligation at the time of the test or event. The success or lack of success of an unannounced ERCOT test or event is determined by the criteria specified in Section 8.1.3.2.

(c) An ERS Generator that is co-located with an ERS Load and is being evaluated jointly with the ERS Load will be considered unavailable for all 15-minute intervals that are part of an unsuccessful unannounced ERCOT test or event, as well as any subsequent intervals following the end of the test up to the interval immediately preceding the first full 15-minute interval for which the combined performance of the ERS Load and ERS Generator is greater than or equal to the combined obligation at the time of the test or event. The success or lack of success of an unannounced ERCOT test or event is determined by the criteria specified in Section 8.1.3.2.

(d) An ERS Generator will be considered unavailable during any 15-minute interval of an obligated ERS Time Period in which any of the following conditions are present:

(i) The ERS Generator output is greater than the sum of its self-serve capacity and its declared injection capacity for the ERS Time Period;

(ii) The export to the grid for the ERS Generator is greater than the injection capacity for the ERS Time Period;

(iii) Required metered interval data was not provided to ERCOT by the time ERCOT calculated availability for one or more sites in the ERS Resource.

(e) ERCOT shall exclude any 15-minute intervals meeting one or more of the following descriptions from the availability:

(i) Any 15-minute interval in which the ERS Generator was deployed during an ERS deployment event or unannounced test, including intervals that begin during the ten-hour ERS recovery period following the issuance of the recall instruction; and

(ii) 15-minute intervals during a successfully completed ERCOT unannounced test of the ERS Generator including intervals that begin during the ten-hour ERS recovery period.

ERCOT Impact Analysis Report

NPRR Number	**1106**	**NPRR Title**	**Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)**
Impact Analysis Date	November 4, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	ERCOT will update its grid operations and practices to implement this NPRR.		

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

Comments
None.

Board Report

NPRR Number	**1107**	**NPRR Title**	**Addition of Weatherization Inspection Fees to the ERCOT Fee Schedule and Clarification of Generation Interconnection Request Fees**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to allow for the recovery of costs associated with performing weatherization inspections scheduled to begin in December 2021. Further, the moratorium on Distribution Generation Resources (DGRs) interconnection is scheduled to expire in early 2022 and clarification is needed that DGRs will be subject to Generation Interconnection or Change Request (GINR) fees like other generation projects.		
Proposed Effective Date	Upon system implementation until September 1, 2022		
Priority and Rank Assigned	Not Applicable		
Nodal Protocol Sections Requiring Revision	ERCOT Fee Schedule		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) adds new fees for weatherization inspections conducted by ERCOT to the ERCOT Fee Schedule. This NPRR further clarifies that the existing GINR fees apply to all generation interconnection projects regardless of whether they will interconnect at the transmission or distribution level.		
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☒ Regulatory requirements		

Board Report

	☐ Other: (explain) *(please select all that apply)*
Business Case	Pursuant to Senate Bill 3 (SB3) and P.U.C. SUBST. R. 25.55, Weather Emergency Preparedness, ERCOT is required to perform new weatherization tasks, including conducting inspections of Generation Resources and Transmission Facilities. At its August 10, 2021 meeting, the ERCOT Board of Directors approved the recommendation to recover costs relating to the SB3 weatherization inspections separately from the System Administration fee for the 2022 and 2023 Biennial Budget. Further, clarification of the applicability of GINR fees is needed before the expiration of the DGR moratorium in early 2022.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1107 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 11/10/21, PRS voted via roll call to waive notice for NPRR1107, and to grant NPRR1107 Urgent status. There were two opposing votes from the Independent Generator (Luminant) and Municipal (Denton) Market Segments, and seven abstentions from the Consumer (2) (OPUC, Occidental Chemical), Independent Generator (Jupiter Power), Independent Power Marketer (IPM) (3) (Tenaska, DC Energy, Morgan Stanley), and Municipal (Austin Energy) Market Segments. PRS then voted unanimously via roll call to table NPRR1107. All Market Segments participated in the votes. On 11/17/21, PRS voted via roll call to recommend approval of NPRR1107 as amended by the 11/16/21 TIEC comments and to forward to TAC NPRR1107 and the Impact Analysis with a recommended effective date of upon PUCT approval and a recommended sunset date of September 1, 2022. There were four opposing votes from the Independent Generator (3) (Broad Reach, Jupiter Power, ENGIE) and Municipal (GEUS) Market Segments, and three abstentions from the Consumer (Occidental Chemical), IPM (Morgan Stanley), and Independent Retail Electric Provider (IREP) (Just Energy) Market Segments. All Market Segments participated in the vote.
Summary of PRS Discussion	On 11/10/21, ERCOT Staff reviewed NPRR1107. Some participants requested clarification as to how the Weatherization Inspection fee will be applied towards various Resource types and sites that contain multiple Resources. Some participants also expressed concern regarding the fee's cost and interest rate and proposed paying ERCOT directly for inspections as opposed to via cost-raising, third-

	party vendors. Participants requested that ERCOT provide additional, clarifying materials at the next PRS meeting. In consideration of the 2021 Generation Entity Winter Weather Preparedness Workshop, participants requested PRS table NPRR1107 for further discussion at a special PRS meeting. On 11/17/21, participants reviewed the 11/15/21 ERCOT, 11/16/21 Joint Commenters, and 11/16/21 TIEC comments. Participants requested clarification as to how weatherization inspections are performed, what criteria constitutes an inspection, and how inspection costs are configured. Some participants also expressed concern regarding disproportionate cost distribution. Participants examined the practicalities of the Joint Commenters' and TIEC's approach to the collection and allocation of costs in contrast with ERCOT's approach. Participants also expressed the need to initiate an inspection plan quickly and requested an opportunity to return to the topic of weatherization inspection in 2022 to recalibrate the process per lessons learned.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NPRR1107 as recommended by PRS in the 11/17/21 PRS Report as amended by the 11/23/21 ERCOT comments and the Revised Impact Analysis. There were two abstentions from the Independent Generator (ENGIE, Avangrid) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the 11/23/21 ERCOT comments, Revised Impact Analysis, ERCOT Opinion and ERCOT Market Impact Statement for NPRR1107. Participants expressed support for the 11/23/21 ERCOT comments and encouraged ERCOT to reform its approach to determining weatherization inspection fees for 2022.
ERCOT Opinion	ERCOT supports approval of NPRR1107.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1107 and believes the market impact for NPRR1107 addresses current regulatory requirements by adding weatherization inspection fees to the ERCOT Fee Schedule and clarifying that existing GINR fees apply to all generation interconnection projects.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1107 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor

Board Report

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Market Segment	Not Applicable

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Comments Received	
Comment Author	**Comment Summary**
ERCOT 111521	Clarified that inspection fees will be charged per Resource or Transmission Facility that is inspected; and that Combined Cycle Trains will be charged one inspection fee per inspected unit and that payments for Invoices will be due within 30 days after the Invoice date
Joint Commenters 111621	Adjusted the allocation of Weatherization Inspection fees to apply across all Resource Entities rather than to a subset of Resource Entities
TIEC 111621	Limited the applicability of the Weatherization Inspection fee to Resource Entities representing Generation Resources
ERCOT 112321	Proposed using the Resource Integration and Ongoing Operations-Resource Services ("RIOO-RS") database as the source for the underlying calculation data due to its ability to run reports based upon specific queries

Market Rules Notes

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

- NPRR1067, Market Entry Qualifications, Continued Participation Requirements, and Credit Risk Assessment
  - ERCOT Fee Schedule

Proposed Protocol Language Revision

ERCOT Fee Schedule

TBD

The following is a schedule of ERCOT fees currently in effect.

Description	Nodal Protocol Reference	Calculation/Rate/Comment
ERCOT System Administration fee	9.16.1	$0.555 per MWh to fund ERCOT activities subject to Public Utility Commission of Texas (PUCT) oversight. This fee is charged to all Qualified Scheduling Entities (QSEs) based on Load represented.
Private Wide Area Network fees	9.16.2	Actual cost of using third party communications network - Initial equipment installation cost not to exceed $25,000, and monthly network management fee not to exceed $1,500.
ERCOT Generation Interconnection fee (Not Refundable)	NA	Application to interconnect generation to the ERCOT System. $5,000 (less than or equal to 150MW) $7,000 (greater than 150MW)
Full Interconnection Study Application fee (Not Refundable)	NA	$15 per MW – to support ERCOT system studies and coordination. Applicable MW amount per Planning Guide Section 5, Generation Resource Interconnection or Change Request.
Map Sale fees	NA	$20 - $40 per map request (by size)
Qualified Scheduling Entity Application fee	9.16.2	$500 per Entity
Competitive Retailer Application fee	9.16.2	$500 per Entity
Congestion Revenue Right (CRR) Account Holder Application fee	9.16.2	$500 per Entity
Independent Market Information System Registered Entity fee (IMRE)	9.16.2	$500 per Entity
Weatherization Inspection fees	NA	Resource Entities and Transmission Service Providers (TSPs) shall pay fees to ERCOT for costs related to weatherization inspections conducted pursuant to 16 Texas Administrative Code (TAC) § 25.55 as provided below. TSPs shall pay an inspection fee of $3,000 for each of their substations or switching stations that are inspected.

		Each Resource Entity shall pay an inspection fee calculated as the Quarterly Generation Resource Inspection Costs * (Resource Entity MW Capacity/Aggregate MW Capacity). ERCOT will perform this calculation for each calendar quarter and gather the necessary MW capacity data for that quarter on one of the last 15 Business Days at the end of the quarter. Terms used in this formula are defined as follows: Quarterly Generation Resource Inspection Costs = the sum of outside services costs, ERCOT internal costs, and overhead costs related to weatherization inspections, less inspection fees that will be invoiced to TSPs for that quarter. Resource Entity MW Capacity = the total MW capacity associated with a Resource Entity. To calculate these amounts, ERCOT will query the Resource Integration and Ongoing Operations-Resource Services ("RIOO-RS") for a report that lists the total MW capacity (real power rating) for all generation assets associated with each Resource Entity. Aggregate MW Capacity = the total of all the Resource Entity MW Capacity amounts. To calculate this amount, ERCOT will query the RIOO-RS for a report that lists the total MW capacity (real power rating) for all generation assets associated with all Resource Entities. ERCOT will issue Invoices in the first month following each calendar quarter to the Resource Entities and TSPs that owe inspection fees. Payment of the fee will be due within 30 days of the Invoice date and late payments will incur 18% annual interest. Entities that fail to pay their Invoice on time will be publicly reported in a filing with the PUCT. Further payment terms and instructions will be included on the Invoice.
Voluminous Copy fee	NA	$0.15 per page in excess of 50 pages

Revised ERCOT Impact Analysis Report

NPRR Number	**1107**	**NPRR Title**	**Addition of Weatherization Inspection Fees to the ERCOT Fee Schedule and Clarification of Generation Interconnection Request Fees**
Impact Analysis Date	November 23, 2021		
Estimated Cost/Budgetary Impact	Less than $10k, which will be absorbed by the Operations & Maintenance (O&M) budgets of affected department.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect within 1-2 months after Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • ERCOT Website and MIS Systems 100%		
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	1109	NPRR Title	Process for Reinstating Decommissioned Generation Resources
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to allow at least one Decommissioned Generation Resource to return to service for part of the 2021-2022 winter Peak Load Season.		
Proposed Effective Date	Upon Public Utility Commission of Texas (PUCT) approval – December 17, 2021		
Priority and Rank Assigned	Not Applicable		
Nodal Protocol Sections Requiring Revision	3.14.1.9, Generation Resource Status Updates Section 22, Attachment H, Notification of Change of Generation Resource Designation		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) allows a Resource Entity to bring a Decommissioned Generation Resource back to service if it submits a Notification of Change of Generation Resource Designation notifying ERCOT of the intended return to service within three years of the date the Generation Resource was removed from the ERCOT Network Operations Model. This NPRR gives ERCOT and the interconnecting Transmission and/or Distribution Service Provider (TDSP) discretion to require any needed studies testing, metering, or facility upgrades to ensure the reliable interconnection of the Generation Resource.		
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements		

Board Report

	☐ Other: (explain) *(please select all that apply)*
Business Case	This NPRR will enable Generation Resources that have been recently decommissioned and retired to return to service to provide needed generation capacity. ERCOT is aware of one Decommissioned Generation Resource that will likely be able to return for part of the 2021-2022 winter Peak Load Season. Today, the Protocols would require such a Resource to follow the interconnection process for a new Generation Resource. Because recently retired Resources will not generally present material reliability issues that would need to be studied, ERCOT does not believe it is necessary to require such Resources to follow the usual interconnection process. However, to address any concern that such a Resource could cause any reliability issue, this NPRR would grant ERCOT and the interconnecting TDSP the authority to require any studies, testing, metering, or upgrades they deem necessary. ERCOT would also have authority to require the Resource Entity to address any operational concern prior to the operation of the Resource.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1109 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 11/10/21, PRS voted via roll call to waive notice for NPRR1109, and to grant NPRR1109 Urgent status. There were two opposing votes from the Independent Generator (Luminant) and Municipal (Denton) Market Segments, and seven abstentions from the Consumer (2) (OPUC, Occidental), Independent Generator (Jupiter Power), Independent Power Marketer (IPM) (3) (DC Energy, Morgan Stanley, Tenaska), and Municipal (Austin Energy) Market Segments. PRS then voted unanimously via roll call to table NPRR1109. All Market Segments participated in the votes. On 11/17/21, PRS voted via roll call to recommend approval of NPRR1109 as submitted and to forward to TAC NPRR1109 and the Impact Analysis with a recommend effective date of upon PUCT approval. There were two opposing votes from the Independent Generator (Luminant) and IPM (Morgan Stanley) Market Segments, and 12 abstentions from the Independent Generator (5) (Broad Reach, Key Capture, Jupiter, Calpine, EDP Renewables), IPM (Tenaska), Independent Retail Electric Provider (IREP) (2) (Reliant, Just Energy), Investor Owned Utility (IOU) (AEP), and Municipal (3) (Denton, Austin Energy, CPS Energy) Market Segments. All Market Segments participated in the vote.

Board Report

Summary of PRS Discussion	On 11/10/21, ERCOT Staff reviewed NPRR1109. Some participants expressed concern that NPRR1109 unnecessarily revises ERCOT's test and study processes and poses safety and reliability risks and market impacts, and suggested that a good cause exception for one unit would be more appropriate than an NPRR, as it would achieve the goal of additional MWs available for the 2021-2022 winter Peak Load Season without altering the established process and risking unintended consequences. In consideration of the 2021 Generation Entity Winter Weather Preparedness Workshop, participants requested PRS table NPRR1109 for further discussion at a special PRS meeting. On 11/17/21, participants expressed support for bringing as many additional MWs possible to the market for the 2021-2022 winter Peak Load Season, but voiced concern for NPRR1109's timeline. Some participants expressed concern that decommissioned units will not actually be ready for operation in sufficient time, that repairs to a unit may impact studies or models, and that NPRR1109 changes the meaning of "retirement" and circumvents the mothball return-to-service process. Participants also discussed whether a good cause exception might be sought with the PUCT rather than revising the ERCOT Protocols on an urgent timeline.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NPRR1109 as recommended by PRS in the 11/17/21 PRS Report with a recommended effective date of upon PUCT approval (12/17/21). There were two opposing votes from the IPM (Morgan Stanley) and IREP (Demand Control 2) Market Segments, and six abstentions from the Independent Generator (2) (Luminant, Calpine), IPM (Shell Energy), IREP (2) (Reliant Energy, Just Energy), and Municipal (CPS Energy) Market Segments. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for NPRR1109. Supporters offered that NPRR1109 provides ERCOT a framework in the short term, and that an alternative process for reinstating Decommissioned Generation Resources may be developed in the long term.
ERCOT Opinion	ERCOT supports approval of NPRR1109.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1109 and believes the market impact for NPRR1109 enables Generation Resources that have been recently decommissioned and retired to return to service to provide needed generation capacity while also granting ERCOT and the interconnecting TDSP the authority to require any studies, testing, metering, or upgrades deemed necessary, and ERCOT the

	authority to require the Resource Entity to address any operational concern prior to the operation of the Resource.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1109 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
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Market Segment	Not Applicable

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Protocol Language Revision

3.14.1.9 Generation Resource Status Updates

(1) By April 1st and October 1st of each year and when material changes occur, every Resource Entity that owns or controls a Mothballed Generation Resource or an RMR Unit shall report to ERCOT, on a unit-specific basis, the estimated lead time required for each Resource to be capable of returning to service and, in percentage terms, report probable generation capacity from each Resource that the Resource Entity expects to return to service in each Season of each of the next ten years.

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

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

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

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

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

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

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

(9) A Resource Entity with a Mothballed Generation Resource that is not currently mothballed indefinitely must notify ERCOT in writing, by completing an NSO (Section

22, Attachment E), no less than 150 days before the date on which the Mothballed Generation Resource is to be suspended indefinitely or retired and decommissioned.

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

(11) If ERCOT and the Resource Entity or QSE cannot reach a mutual agreement to make the Mothballed Generation Resource operating under a Seasonal Operation Period available earlier than June 1st or later than September 30th of any given calendar year, then ERCOT may exercise its ability to bring the Mothballed Generation Resource operating under a Seasonal Operating Period into the market under an RMR Agreement pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority.

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

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

(14) Before retiring and decommissioning either a Mothballed Generation Resource this is mothballed indefinitely or an RMR Unit that would otherwise become a Mothballed Generation Resource upon expiration of an RMR Agreement, a Resource Entity shall notify ERCOT of the expected retirement by submitting a completed Notification of Change of Generation Resource Designation form (Section 22, Attachment H). The date of retirement indicated on the form shall comply with the requirements of Section 3.10.1, Time Line for Network Operations Model Changes.

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

and TSPs will consider the Generation Resource mothballed until the Resource Entity indicates a definitive return to service date pursuant to this Section.

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

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

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

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

ERCOT Nodal Protocols

Section 22

Attachment H: Notification of Change of Generation Resource Designation

TBD

Notification of Change of Generation Resource Designation

This Notification is for changing a Generation Resource designation in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary.

The Notification must be signed, notarized and delivered to ERCOT. Delivery may be accomplished via email to MPRegistration@ercot.com (if a scanned copy) or via facsimile (Attention: Market Participant Registration) at (512) 225-7079. ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

Resource Entity: ____

DUNS No.: ____

Generation Resource(s) [plant and unit number(s)] ______________________

Generation Resource(s) is currently [check one]

☐ decommissioned and retired

☐ under a Reliability Must-Run (RMR) Agreement

☐ mothballed under a Seasonal Operation Period

☐ mothballed

As of _______ [date], Resource Entity will change the Generation Resource(s) designation to [check one]

☐ operational (for a Mothballed Generation Resource operating under a Seasonal Operation Period, selecting this option means that the Generation Resource is returning to year round service)

☐ mothballed (a Mothballed Generation Resource operating under a Seasonal Operation Period may not select this option, and must instead use the Section 22, Attachment E, Notification of Suspension of Operation form to change to a different mothballed status)

☐ decommissioned and retired permanently[1] (a Mothballed Generation Resource operating under a Seasonal Operation Period may not select this option and must instead use the form in Section 22, Attachment E to be designated as decommissioned)

☐ Mothballed Generation Resource operating under a Seasonal Operation Period, updating start date or end date of Seasonal Operation Period

As of __________ [date], a Mothballed Generation Resource will change its Seasonal Operation Period as follows:

☐ change start date of Seasonal Operation Period from _____ to _____

☐ change end date of Seasonal Operation Period from _____ to _____

The undersigned certifies that I am an officer of Resource Entity, that I am authorized to execute and submit this Notification on behalf of Resource Entity, and that the statements contained herein are true and correct.

____

Name: ______________________________

Title: _______________________________

Date: _______________________________

STATE OF _______________

[1] In accordance with Section 3.14.1.9, Generation Resource Status Updates, ERCOT will remove the Generation Resource(s) from its registration upon Resource Entity updating Resource Registration accordingly.

Board Report

COUNTY OF _____________

Before me, the undersigned authority, this day appeared ___________________, known by me to be the person whose name is subscribed to the foregoing instrument, who, after first being sworn by me deposed and said:

> "I am an officer of ______________, I am authorized to execute and submit the foregoing Notification on behalf of ______________, and the statements contained in such Notification are true and correct."

SWORN TO AND SUBSCRIBED TO BEFORE ME, the undersigned authority on this the _____ day of ____________, 20__.

____

Notary Public, State of ___________

My Commission expires __________

ERCOT Impact Analysis Report

NPRR Number	1109	NPRR Title	Process for Reinstating Decommissioned Generation Resources
Impact Analysis Date	November 9, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	ERCOT will update its grid operations and practices to implement this NPRR.		

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

Comments
None.

Board Report

NOGRR Number	233	NOGRR Title	Related to NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3
Date of Decision		December 10, 2021	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		Upon implementation of Nodal Protocol Revision Request (NPRR) 1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3	
Priority and Rank Assigned		Not applicable	
Nodal Operating Guide Sections Requiring Revision		2.6.1, Automatic Firm Load Shedding	
Related Documents Requiring Revision/Related Revision Requests		NPRR1094 Nodal Operating Guide Section 4.5.3.3, EEA Levels	
Revision Description		This Nodal Operating Guide Revision Request (NOGRR) will allow a Transmission Operator (TO) and a Transmission and/or Distribution Service Provider (TDSP) to manually shed Load connected to under-frequency relays during an Energy Emergency Alert (EEA) Level 3 if the affected TO can meet its overall Under-Frequency Load Shed (UFLS) requirement in Section 2.6.1 and its Load shed obligation under Section 4.5.3.4, Load Shed Obligation.	
Reason for Revision		☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*	
Business Case		During extreme Load shed events, the amount of Load connected to UFLS feeders will substantially exceed the required percentage	

	levels prescribed in paragraph (1) of Section 2.6.1 due to high system loading and the manual reduction in demand from manual Load shed. The Protocols and Nodal Operating Guide currently state that entities "shall not manually drop Load connected to under-frequency relays during the implementation of Level 3 of an Energy Emergency Alert (EEA)." The modifications proposed in this NOGRR remove the prohibition from manually shedding any UFLS feeder-connected Load during an EEA Level 3. TOs/TDSPs would be allowed to shed UFLS feeder-connected Load as long as they continue to maintain the required percentage levels of UFLS. This modification provides the following benefits: 1) TOs can utilize the "margin" in their UFLS-represented Load to shed Load and rotate outages. This substantially increases the amount of Load available for rotating outages, which spreads the burden of those outages to a larger and more diverse pool of Load. 2) Reduces the risk of a significant overshoot in frequency in the event of a UFLS operation while UFLS levels substantially exceed the required levels. Oncor requests consideration of this NOGRR in a timeline that would allow it to be considered during the December 2021 ERCOT Board of Directors meeting, which should enable the operational changes described to be reflected in TO/DSP Winter 2021/2022 Load shed plans.
ROS Decision	On 10/7/21, ROS voted unanimously via roll call to recommend approval of NOGRR233 as submitted. All Market Segments participated in the vote. On 11/4/21, ROS voted unanimously via roll call to endorse and forward to TAC the 10/7/21 ROS Report and the Impact Analysis for NOGRR233. All Market Segments participated in the vote.
Summary of ROS Discussion	On 10/7/21, the sponsor provided an overview of NOGRR233. Participants discussed timeline considerations and noted that Operations Working Group (OWG) had already elected to discuss this item at its September 14, 2021 meeting. On 11/4/21, there was no discussion.
TAC Decision	On 11/29/21, TAC voted unanimously via roll call to recommend approval of NOGRR233 as recommended by ROS in the 11/4/21

	ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for NOGRR233.
ERCOT Opinion	ERCOT supports approval of NOGRR233.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR233 and believes NOGRR233 improves efficiency and reliability by removing restrictions on manually shedding UFLS feeder-connected Load during an EEA Level 3.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NOGRR233 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Collin Martin
E-mail Address	collin.martin@oncor.com
Company	Oncor Electric Delivery Company LLC
Phone Number	817-215-6174
Cell Number	
Market Segment	Investor Owned Utility (IOU)

Market Rules Staff Contact	
Name	Phillip Bracy
E-Mail Address	Phillip.Bracy@ercot.com
Phone Number	512-248-6917

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):

- NOGRR226, Revision to 5% Transmission Operator (TO) Load Shedding Relay Set Point
  - Section 2.6.1

Proposed Guide Language Revision

2.6 Requirements for Under-Frequency and Over-Frequency Relaying

2.6.1 Automatic Firm Load Shedding

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in the table below. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.3 Hz threshold. As such, the amount of the TO Load relief will not include any Load that has already been shed prior to the 59.3 Hz frequency threshold. The under-frequency relays shall be set to provide Load relief as follows:

Frequency Threshold	TO Load Relief
59.3 Hz	At least 5% of the TO Load
58.9 Hz	A total of at least 15% of the TO Load
58.5 Hz	A total of at least 25% of the TO Load

(2) ERCOT will, prior to the peak each year, survey each TO's compliance with the automatic Load shedding requirements described in paragraph (1) above, and report its findings to the Technical Advisory Committee (TAC). For purposes of determining a TO's compliance with this annual survey requirement, TO Load will be the total amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, at the specified time of the survey. The TO shall identify those circuits armed with under-frequency relays, the corresponding amount of Load, and identify the frequency threshold. A TO shall not equip the entirety of its Load shed obligation in any one tier, and should endeavor to shed in controlled amounts that equal the difference between the TO Load relief required for each tier. If ERCOT identifies potential reliability issues related to distribution of Load shed across the tiers, ERCOT may require the TO to redistribute Load relief closer to the minimum amount required after submitting ERCOT's proposal to redistribute Load relief to the TO and considering any comments submitted by the TO regarding the proposal. Compliance with this annual survey does not excuse the TO from compliance with the requirements

of paragraph (1) above in an actual frequency event. To assist TOs, ERCOT will provide the TO's inventory, including substation and capacity amounts, of registered Load Resources in its area within ten Business Days of receiving a request in writing from a TO.

(3) Additional under-frequency relays may be installed on Transmission Facilities with the approval of ERCOT provided the relays are set at 58.0 Hz or below, are not directional, and have at least 2.0 seconds time delay. A DSP may by mutual agreement arrange to have all or part of its automatic Load shedding requirement performed by another entity. ERCOT will be notified and provided with the details of any such arrangement prior to implementation.

(4) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay of no more than 30 cycles. Total time from the time when frequency first reaches one of the values specified above to the time Load is interrupted should be no more than 40 cycles, including all relay and breaker operating times. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

[NOGRR212: Replace paragraph (4) above with the following upon system implementation of NPRR1016:]

(4) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) are connected to circuits that are not subject to disconnection during UFLS events, except as permitted by Nodal Protocol Section 3.8.7, Distribution Generation Resources (DSRs) and Distribution Energy Storage Resources (DESRs). DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay of no more than 30 cycles. Total time from the time when frequency first reaches one of the values specified above to the time Load is interrupted should be no more than 40 cycles, including all relay and breaker operating times. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

(5) If a loss of Load occurs due to the operation of under-frequency relays, a DSP or its designee may rotate the physical Load interrupted to minimize the duration of interruption experienced by individual Customers or to restore the availability of under-frequency Load-shedding capability. In no event shall the initial total amount of Load without service be decreased without the approval of ERCOT. TOs, in coordination with

DSPs, shall make every reasonable attempt to restore Load, either by automatic or manual means, to preserve system integrity. Restoration of any Load shed by UFLS systems shall be coordinated with ERCOT by the TO. In the event frequency drops below any of the frequency thresholds specified in the table in paragraph (1) above, and a TO's UFLS relays that previously activated as a result of reaching that same frequency threshold have not been restored since the previous excursion, the Load on the feeders controlled by those relays shall be counted toward the TO's satisfaction of the percentages in paragraph (1) above for that subsequent frequency excursion.

ERCOT Impact Analysis Report

NOGRR Number	233	NOGRR Title	Related to NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3
Impact Analysis Date	October 19, 2021		
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) 1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3.		
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 NPRR1094.

Board Report

NOGRR Number	<u>236</u>	**NOGRR Title**	**Related to NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to implement in the ERCOT Nodal Operating Guide the direction provided by the Public Utility Commission of Texas (PUCT) and the ERCOT Board at the October 22, 2021 ERCOT Board of Directors meeting/PUCT Open Meeting.		
Proposed Effective Date	Upon implementation of Phase 1 of Nodal Protocol Revision Request (NPRR) 1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)		
Priority and Rank Assigned	Not Applicable		
Nodal Operating Guide Sections Requiring Revision	4.5.3.1, General Procedures Prior to EEA Operations		
Related Documents Requiring Revision/Related Revision Requests	NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA) Nodal Operating Guide Section 4.5.3.3, EEA Levels ERCOT Operating Procedures – Transmission and Security ERCOT Operating Procedures – Scripts		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) provides ERCOT the ability to instruct Transmission and/or Distribution Service Providers (TDSPs) to deploy any available distribution voltage reduction measures prior to ERCOT declaring an Energy Emergency Alert (EEA) if ERCOT determines it is possible that the deployment of these measures could avoid the need to declare an EEA and ERCOT does not expect to need these measures to reduce the amount of Load shedding that may be needed in EEA Level 3. These revisions also clarify the role of TDSPs in determining whether distribution voltage reduction should be implemented.		
Reason for Revision	☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the <u>ERCOT Strategic Plan</u> or directed by the ERCOT Board).		

	☐ Market efficiencies or enhancements ☐ Administrative ☒ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	This NOGRR is proposed based upon PUCT and ERCOT Board direction provided at the October 22, 2021 ERCOT Board of Directors meeting/PUCT Open Meeting. These revisions provide ERCOT the additional tool of voltage reduction measures before declaration of an EEA while also taking into consideration whether the earlier implementation of these measures would reduce their effectiveness in mitigating the amount of Load shed during an EEA Level 3 Load-shedding event.
ROS Decision	On 11/17/21, ROS voted via email to grant NOGRR236 Urgent status; to recommend approval of NOGRR236 as amended by the 11/8/21 STEC comments; and to forward to TAC NOGRR236 and the Impact Analysis. There was one opposing vote from the Independent Generator (Calpine) Market Segment, and one abstention from the Municipal (CPS Energy) Market Segment. All Market Segments participated in the vote.
Summary of ROS Discussion	On 11/17/21, there was no discussion.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NOGRR236 as recommended by ROS in the 11/17/21 ROS Report. There were two opposing votes from the IPM (Morgan Stanley) and IREP (Demand Control 2) Market Segments, and four abstentions from the Municipal (4) (Garland, Denton, Austin Energy, CPS Energy) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for NOGRR236. Please see the 11/29/21 TAC Report for the TAC discussion on NPRR1005.
ERCOT Opinion	ERCOT supports approval of NOGRR236.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR236 and believe the market impact for NOGRR236 enhances ERCOT's operational tools to address potential reliability outcomes by providing ERCOT the additional tool of voltage reduction measures before declaration of

	an EEA while also taking into consideration whether the earlier implementation of these measures would reduce their effectiveness in mitigating the amount of Load shed during an EEA Level 3 Load-shedding event.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NOGRR236 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Dan Woodfin
E-mail Address	Dan.Woodfin@ercot.com
Company	ERCOT
Phone Number	512-248-3115
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**
STEC 110821	Clarified there is no obligation for any party to invest in voltage reduction capabilities; clarified that parties will not be held responsible for ensuring that a voltage reduction action would not create adverse issues on the transmission or distribution system

Market Rules Notes

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

- NOGRR237, Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
    - 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 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.

ERCOT Impact Analysis Report

NOGRR Number	236	NOGRR Title	Related to NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
Impact Analysis Date	November 4, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon system implementation of NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)		
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 NPRR1105.

Board Report

NOGRR Number	237	NOGRR Title	Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
Date of Decision		December 10, 2021	
Action		Recommended Approval	
Timeline		Urgent – to implement revisions to the Emergency Response Service (ERS) deployment process in time for the winter season.	
Proposed Effective Date		Upon implementation of Nodal Protocol Revision Request (NPRR) 1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)	
Priority and Rank Assigned		Not Applicable	
Nodal Operating Guide Sections Requiring Revision		4.5.3.1, General Procedures Prior to EEA Operations	
Related Documents Requiring Revision/Related Revision Requests		NPRR1106 Nodal Operating Guide Section 4.5.3.3, EEA Levels Other Binding Document Revision Request (OBDRR) 036, Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of EEA ERCOT Operating Procedures – Real-Time Desk ERCOT Operating Procedures – Resource Desk ERCOT Operating Procedures – Scripts Emergency Response Service Procurement Methodology Emergency Response Service Technical Requirements & Scope of Work	
Revision Description		This Nodal Operating Guide Revision Request (NOGRR) aligns the Nodal Operating Guide with Protocol changes proposed by NPRR1106, allowing ERCOT to deploy ERS prior to an Energy Emergency Alert (EEA).	
Reason for Revision		☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board).	

Board Report

	[X] Market efficiencies or enhancements [ ] Administrative [X] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*
Business Case	In Public Utility Commission of Texas (PUCT) Docket No. 52373, Review of Wholesale Electric Market Design, PUCT Staff filed a Motion for Good Cause Exception that requested the PUCT grant ERCOT a good cause exception pursuant to P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), "so that ERCOT may procure ERS that may be used prior to the declaration of an EEA, rather than being limited to use of the ERS during an EEA, as allowed by 16 TAC § 25.507(a)." The PUCT voted to grant this exception at its October 28, 2021 Open Meeting. To effectuate the PUCT's direction, ERCOT has proposed NPRR1106. This NOGRR aligns the Nodal Operating Guide with Protocol changes proposed by NPRR1106.
ROS Decision	On 11/17/21, ROS voted via email to grant NOGRR237 Urgent status; to recommend approval of NOGRR237 as submitted; and to forward to TAC NOGRR237 and the Impact Analysis. There were two abstentions from the Consumer (OPUC) and Independent Retail Electric Provider (IREP) (Demand Control 2) Market Segments. All Market Segments participated in the vote.
Summary of ROS Discussion	On 11/17/21, there was no discussion.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NOGRR237 as recommended by ROS in the 11/17/21 ROS Report. There was one opposing vote from the Independent Power Marketer (IPM) (Morgan Stanley) Market Segment, and one abstention from the Municipal (Garland) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for NOGRR237.
ERCOT Opinion	ERCOT supports approval of NOGRR237.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR237 and believes the market impact for NOGRR237 enhances ERCOT's operational tools to

	address potential reliability outcomes by granting ERCOT operators the discretion to deploy ERS when Physical Responsive Capability (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-Spinning Reserve (Non-Spin).
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NOGRR237 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Sandip Sharma
E-mail Address	Sandip.Sharma@ercot.com
Company	ERCOT
Phone Number	512-248-4298
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

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):

- NOGRR236, Related to NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
  - 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 Non-Spinning Reserve (Non-Spin) services as required; and

[NPRR863: Replace item (d) above with the following upon system implementation:]

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

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

(2) 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, ERCOT may deploy available contracted ERS-10 and ERS-30 via an XML message followed by a VDI to the QSE Hotline. The ERS-10 and ERS-30 ramp periods shall begin at the completion of the VDI.

(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 releases 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 release of ERS-10 and ERS-30 via an XML message followed by VDI to the QSE Hotline. The VDI shall represent the official notice of ERS-10 and ERS-30 release.

(d) Upon release, 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 release.

ERCOT Impact Analysis Report

NOGRR Number	237	NOGRR Title	Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
Impact Analysis Date	November 4, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon system implementation of NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA).		
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 NPRR1106.

Board Report

OBDRR Number	<u>035</u>	**OBDRR Title**	**Related to NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Proposed Effective Date	Upon system implementation of Nodal Protocol Revision Request (NPRR) 1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve		
Priority and Rank Assigned	Not applicable		
Other Binding Document Requiring Revision	Non-Spinning Reserve Service Deployment and Recall Procedure		
Supporting Protocol or Guide Section(s) / Related Documents	NPRR1101		
Revision Description	This Other Binding Document Revision Request (OBDRR) aligns the Non-Spinning Reserve Deployment and Recall Procedure with revisions from NPRR1101.		
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the <u>ERCOT Strategic Plan</u> or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*		
Business Case	NPRR1101 modifies the grouping requirements for Load Resources that are not Controllable Load Resources ("NCLRs") providing Non-Spinning Reserve (Non-Spin) to include Generation Resources providing Off-Line Non-Spin. NCLRs providing Non-Spin and Generation Resources providing Off-Line Non-Spin will be assigned to a deployment group based on random selection. This OBDRR		

Board Report

	and NPRR1101 will facilitate Non-Spin deployment for non-local issues in groups of roughly 500 MW which may include both NCLRs and Generation Resources. Alignment between the Protocols and Other Binding Documents is necessary and proper. ERCOT is filing this OBDRR and NPRR1101 in response to stakeholder feedback received regarding NPRR1093 and after the Non-Spinning Reserve (Non-Spin) Service Workshop held by TAC on October 19, 2021.
TAC Decision	On 11/29/21, TAC unanimously voted via roll call to recommend approval of OBDRR035 as amended by the 11/19/21 ERCOT comments; and the Impact Analysis for OBDRR035. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and 11/19/21 ERCOT comments for OBDRR035.
ERCOT Opinion	ERCOT supports approval of OBDRR035.
ERCOT Market Impact Statement	ERCOT Staff has reviewed OBDRR035 and believes the market impact for OBDRR35 will improve ERCOT's ability to deploy Non-Spin Service in a technology agnostic manner, improve offer liquidity, and will allow ERCOT to procure the required quantities of Non-Spin more competitively.
ERCOT Board Decision	On 12/10/21, the ERCOT Board recommended approval of OBDRR035 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
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Market Segment	Not applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
ERCOT 111921	Aligned the proposed revisions with baseline updates from the incorporation of OBDRR032, Non-Spin Changes Related to NPRR1093, Load Resource Participation in Non-Spinning Reserve, into the November 1, 2021 Non-Spinning Reserve Deployment and Recall Procedure

Market Rules Notes

Please note that the baseline language in this Other Binding Document has been updated to reflect the incorporation of the following OBDRR(s) into the Non-Spinning Reserve Deployment and Recall Procedure:

- OBDRR032, Non-Spin Changes Related to NPRR1093, Load Resource Participation in Non-Spinning Reserve (incorporated 11/1/21)

Proposed Other Binding Document Language Revision

1. Nodal Market Non-Spinning Reserve Service Deployment and Recall Procedure

For any Non-Spinning Reserve (Non-Spin) Service that is not continually deployed to Security-Constrained Economic Dispatch (SCED) as part of a standing On-Line Non-Spin deployment, there are four situations that will cause Non-Spin to be deployed:

- Detection of insufficient capacity for energy dispatch during periodic checking of available capacity.
- Disturbance conditions such as a unit trip, sustained frequency decay or sustained low frequency operations.
- SCED not having enough energy available to execute successfully.
- When Off-Line Generation Resource(s) and/or Load Resource(s) that are not Controllable Load Resource(s) providing Non-Spin are the only reasonable option(s) available to the Operator for resolving local issues.

[OBDRR032: Replace the language above with the following upon system implementation of NPRR1093:]

- When Off-Line Generation Resource(s) and/or Load Resource(s) that are not Controllable Load Resource(s) providing Non-Spin are the only reasonable option(s) available to the Operator for resolving local issues.

In each of these cases, the ERCOT operator will make the final decision and initiate the deployment. The ERCOT operator shall deploy Non-Spin in amounts sufficient to respond to the operational circumstances. This means that Non-Spin may be deployed partially over time or may be deployed in its entirety. If Non-Spin is deployed partially, it shall be deployed in increments of 100% of each Resource's capacity. To support partial deployment, ERCOT shall, following the Day-Ahead Market (DAM), rank, for each hour of the Operating Day, the Resources supplying Non-Spin in an economic order based on DAM Settlement Point Prices. Partial Non-Spin deployment and recall decisions shall be based on each Resource's economic cost order.

[OBDRR032: Replace the language above with the following upon system implementation of NPRR1093:]

In each of these cases, the ERCOT operator will make the final decision and initiate the deployment. The ERCOT operator shall deploy Non-Spin in amounts sufficient to respond to the operational circumstances. This means that Non-Spin may be deployed partially over time or may be deployed in its entirety. If Non-Spin is deployed partially, it shall be deployed in increments of 100% of each Resource's capacity. To support partial deployment, ERCOT shall, following the Day-Ahead Market (DAM), rank, for each hour of the Operating Day, the Resources supplying Non-Spin in an economic order based on DAM Settlement Point Prices. Partial Non-Spin deployment and recall decisions shall be based on each Resource's economic cost order. When deploying Non-Spin, the Load Resources that are not Controllable Load Resources will be deployed after other Non-Spin from Off-Line Generation Resources.

2. Non-Spin Deployment

ERCOT may deploy Non-Spin, which has not been deployed as part of a standing On-Line Non-Spin deployment, under the following conditions:

- When (High Ancillary Service Limit (HASL) – Gen – Intermittent Renewable Resource (IRR) Curtailment) – (30-minute net load ramp) < 0 MW, deploy sufficient Non-Spin capacity so that (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) >500 MW.

[OBDRR032: Replace the language above with the following upon system implementation of NPRR1093:]

- When (High Ancillary Service Limit (HASL) – Gen – Intermittent Renewable Resource (IRR) Curtailment) – (30-minute net load ramp) < 0 MW, deploy sufficient Non-Spin capacity so that (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) >500 MW.

[OBDRR032: Delete the language above upon system implementation of NPRR1093.]

- When Physical Responsive Capability (PRC) < 3200 MW and not expected to recover within 30 minutes without deploying reserves, deploy all or a portion of the available Non-Spin capacity.
- When Physical Responsive Capability (PRC) < 2500 MW, deploy all of the available Non-Spin capacity.
- When the North-to-Houston (N_H) Voltage Stability Limit Reliability Margin < 300 MW, deploy Non-Spin (all or partial) in the Houston area as needed to restore reliability margin.
- When Off-Line Generation Resources providing Non-Spin are the only reasonable option available to the Operator for resolving local issues, deploy available Non-Spin capacity on only the necessary individual Resources.
- Load Resources that are not Controllable Load Resources and Generation Resources providing Off-Line Non-Spin will be separated into deployment groups as defined in Nodal Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
- Load Resources that are not Controllable Load Resources and Generation Resources providing Off-Line Non-Spin can be deployed individually, in groups, or as an entire block providing Non-Spin. Deployments that do not encompass an entire block may only be done to manage inertia, congestion, or for other local needs.

If a condition other than those listed above indicates that additional capacity may need to be brought On-Line to manage reliability, operators will evaluate the system condition and deploy Non-Spin as needed if no other better options are available to resolve the system condition. Under emergency, the emergency process will govern the deployment of Non-Spin.

Following a Non-Spin deployment, the following steps should be taken:

2.1. Off-Line Generation Resource reserved for Non-Spin

- The Qualified Scheduling Entity (QSE) will be sent a Resource-specific Dispatch Instruction deployment indicating a time and date stamp, QSE, Dispatch Asset Code, and Deployed MW.
- The Dispatch Instruction for an Off-Line Generation Resource must include the expected amount of *capacity* that will be available for SCED and the anticipated duration of the deployment.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Off-Line Generation Resource has been reduced to zero within 20 minutes of the Dispatch Instruction.
- The QSE must have the Off-Line Generation Resource On-Line with an Energy Offer Curve and the telemetered net generation must be greater than or equal to the Resource's telemetered Low Sustained Limit (LSL) multiplied by P1 where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating Hour" within 25 minutes of the Dispatch Instruction.

- SCED will respond to the changes in Resource Status that are received by telemetry from the QSE.
- Once the Resource is On-Line it is Dispatched as any other Generation Resource including any provisions for processing generation less than the Resource's LSL.
- The Resource must, at a minimum, be capable of providing all the Non-Spin energy to SCED within 30 minutes of the Dispatch Instruction.
- The Load Resource must, at a minimum, be capable of remaining deployed until recalled.

2.2. <u>On-Line Generation Resource with an Energy Offer Curve</u>

- For a Resource that *will not use power augmentation* to provide any portion of its Non-Spin Ancillary Service Resource Responsibility:
    - The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
    - ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
    - The total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
    - A Non-Spin deployment Dispatch Instruction from ERCOT is not required for standing Non-Spin deployments.
- For a Resource that *will use power augmentation* to provide a specific MW portion of its Non-Spin Ancillary Service Responsibility:
    - The QSE shall set the value of the Non-Spin Ancillary Service Schedule to the appropriate value within the 30-second window prior to the start of the delivery hour.
    - The QSE may set the value of the Non-Spin Ancillary Service Schedule equal to the MW amount of Non-Spin that will be provided via power. augmentation; otherwise, the QSE may set the value of the schedule to zero.
    - If the Non-Spin Ancillary Service Schedule is set to zero, then the total amount of capacity reserved on that Resource for Non-Spin shall be considered as a standing Non-Spin deployment Dispatch Instruction for the duration of the Operating Hour.
    - If the Non-Spin Ancillary Service Schedule is set to a non-zero value, then the QSE will be sent a Resource-specific Dispatch Instruction indicating that Non-Spin has been deployed for the total amount of the Non-Spin Schedule.
        - The Dispatch Instruction must include the expected amount of *capacity* that will be available for SCED and the anticipated duration of the deployment.

        - The QSE shall reduce the Resource's Non-Spin Ancillary Service Schedule to zero within 20 minutes following a deployment instruction.
    - ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- The QSE must, at a minimum, ensure that the Normal Ramp Rate represented by the Resource's ramp rate curve is sufficient to allow SCED to fully Dispatch the Resource's Non-Spin Resource Responsibility within 30 minutes, regardless of whether or not the Resource uses power augmentation to provide the service.

2.3. <u>On-Line Generation Resource with Output Schedules</u>

- The QSE shall set the value of the Non-Spin Ancillary Service Schedule to zero within the 30-second window prior to the start of the delivery hour.
- ERCOT will automatically calculate new HASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- If the QSE is sent a Resource-specific Dispatch Instruction indicating that Non-Spin has been deployed:
    - The Dispatch Instruction must include the additional amount of *energy* (MW) that needs to be produced by the Resource and the estimated duration of the deployment.
    - For Dynamically Scheduled Resources (DSRs) providing Non-Spin, as soon as the QSE receives the deployment, the QSE shall adjust the telemetry Output Schedule to reflect the Non-Spin deployment. A DSR QSE with a Load Resource that has provided Non-Spin will ensure that the Output Schedule is not reduced to reflect the Load deployment if the Load Resource is part of the DSR Load that the Resource follows.
    - For non-DSRs (with Output Schedules) providing Non-Spin, ERCOT shall increase the Output Schedule used in SCED by the difference between telemetered Non-Spin Ancillary Service Resource Responsibility and Ancillary Service Schedule to reflect the amount of Non-Spin energy that is to be provided by the Resource in response to the Non-Spin deployment.

2.4 <u>Controllable Load Resource with Non-Spin Ancillary Service Resource Responsibility</u>

- The QSE will be sent a Resource-specific Dispatch Instruction that Non-Spin has been deployed.
- The Dispatch Instruction must include the expected amount of capacity that will be available for SCED and the anticipated duration of the deployment.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Controllable Load Resource has been reduced to zero within 20 minutes of the Dispatch Instruction.

- The QSE must have the Controllable Load Resource's telemetered Resource Status as On-Line (ONRGL and/or ONCLR, whichever is applicable) with an RTM Energy Bid, and the Controllable Load Resource's telemetered net real power consumption must be greater than or equal to the Controllable Load Resource's telemetered LPC plus its total upward Ancillary Service Resource Responsibility.
- ERCOT will automatically calculate new LASL constraints for SCED using the telemetry of the Resource's Non-Spin Ancillary Service Schedule.
- Once the Controllable Load Resource's Non-Spin capacity has been released to SCED, this capacity is Dispatched as any other Resource available to SCED.
- The Controllable Load Resource must, at a minimum, be capable of providing all the Non-Spin energy to SCED within 30 minutes of the Dispatch Instruction.

2.5 Load Resource that is not a Controllable Load Resource with Non-Spin Ancillary Service Resource Responsibility

- The QSE must show the Load Resource's telemetered Resource Status as On-Line (ONRL) and, if equipped with an under-frequency relay, the relay should not be armed and the status should indicate Disabled.
- Load Resources that are not Controllable Load Resources and Generation Resources providing offline Non-Spin will be separated into deployment groups as defined in Nodal Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
- The QSE will be sent a Resource-specific Dispatch Instruction for the Non-Spin deployment indicating a time and date stamp, QSE, Dispatch Asset Code, and Deployed MW.
- The Dispatch Instruction must include the expected amount of capacity that will be expected to be dropped by the Load Resource within 30 minutes.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Load Resource has been reduced to zero within one minute of receiving the Dispatch Instruction.
- The Load Resource must, at a minimum, be capable of remaining deployed until recalled.

[OBDRR032: Insert the language below upon system implementation of NPRR1093:]

2.5 Load Resource that is not a Controllable Load Resource with Non-Spin Ancillary Service Resource Responsibility

- The QSE must show the Load Resource's telemetered Resource Status as On-Line (ONRL) and, if equipped with an under-frequency relay, the relay should not be armed and the status should indicate Disabled.

- Load Resources that are not Controllable Load Resources and Generation Resources providing offline Non-Spin will be separated into deployment groups as defined in Nodal Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.
- The QSE will be sent a Resource-specific Dispatch Instruction for the Non-Spin deployment indicating a time and date stamp, QSE, Dispatch Asset Code, and Deployed MW.
- The Dispatch Instruction must include the expected amount of capacity that will be expected to be dropped by the Load Resource within 30 minutes.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for that Load Resource has been reduced to zero within one minute of receiving the Dispatch Instruction.
- The Load Resource must, at a minimum, be capable of remaining deployed until recalled.

3. Recall of Non-Spin Deployment

The deployed Non-Spin may be recalled in a manner that is expected to maintain (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) > 1000 MW and PRC is > 3200 MW. Non-Spin provided by Off-Line Generation Resources and Load Resources that are not Controllable Load Resources will be recalled first, followed by Controllable Load Resources and On-Line Generation Resources until all the Non-Spin is recalled. Non-spin block deployments shall be recalled in the reverse order in which they were deployed or may be recalled all at once, at ERCOT's discretion.

[OBDRR032: Replace the language above with the following upon system implementation of NPRR1093:]

The deployed Non-Spin may be recalled in a manner that is expected to maintain (HASL – Gen – IRR Curtailment) – (30-minute net load ramp) > 1000 MW and PRC is > 3200 MW. Non-Spin provided by Off-Line Generation Resources and Load Resources that are not Controllable Load Resources will be recalled first, followed by Controllable Load Resources and On-Line Generation Resources until all the Non-Spin is recalled. Non-spin block deployments shall be recalled in the reverse order in which they were deployed or may be recalled all at once, at ERCOT's discretion.

Following the recall of a Non-Spin deployment, the following steps should be taken:

- After recall, the QSE for a Generation Resource will be allowed to use normal shutdown procedures to take the Generation Resource Off-Line if the QSE wants to shut down the Resource. In this case, the Non-Spin Ancillary Service Schedule for that Generation Resource will be reset to equal the Non-Spin Ancillary Service Responsibility for that Generation Resource for that hour. A QSE with a Generation Resource that was previously Off-Line will be allowed to keep the Generation Resource On-Line after the minimum On-Line time, provided that the difference between its High Sustained Limit (HSL) and LSL is greater than or equal to its Ancillary Service Resource Responsibility.

- A QSE with a Generation Resource (with an Energy Offer Curve) that will stay On-Line may set the value of the Non-Spin Ancillary Service Schedule equal to the MW amount of Non-Spin that will be provided via power augmentation; otherwise, the QSE will ensure that the value of the Non-Spin Ancillary Service Schedule for that Resource is set to 0 MW.
- A QSE with a DSR Generation Resource (with an Output Schedule) that will stay On-Line will back out the Non-Spin addition that was made to the Output Schedule. This can be incrementally deleted depending on the size of the deployment and Normal Ramp Rate. For non-DSR Generation Resources, SCED will use the QSE-submitted non-DSR Output Schedule once the Non-Spin has been recalled.
- A QSE with a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within three hours of the recall instruction of the Non-Spin deployment. If the QSE cannot restore within three hours of the recall of Non-Spin deployment by ERCOT, the Non-Spin capability must be replaced by the QSE on other Generation or Controllable Load Resources capable of providing the service.
- A QSE with a Load Resource that is not a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within three hours of the recall instruction of the Non-Spin deployment. If the QSE cannot restore within three hours of the ERCOT recall instruction of the Non-Spin deployment, the Non-Spin obligation must be replaced by the QSE from other Non-Spin qualified Resources capable of providing the service.
- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for a Load Resource that is not a Controllable Load Resource continuously and accurately represents the amount of the Load Resource that has been restored following a recall instruction and is available for subsequent deployment.

[OBDRR032: Replace the language above with the following upon system implementation of NPRR1093:]

- A QSE with a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within three hours of the recall instruction of the Non-Spin deployment. If the QSE cannot restore within three hours of the recall of Non-Spin deployment by ERCOT, the Non-Spin capability must be replaced by the QSE on other Generation or Controllable Load Resources capable of providing the service.
- A QSE with a Load Resource that is not a Controllable Load Resource that has provided Non-Spin will ensure that the Load energy and Non-Spin capability is restored within

three hours of the recall instruction of the Non-Spin deployment issued by ERCOT. If the QSE cannot restore within three hours of the ERCOT recall instruction of the Non-Spin deployment, the Non-Spin obligation must be replaced by the QSE from other Non-Spin qualified Resources capable of providing the service.

- The QSE will ensure that the Non-Spin Ancillary Service Schedule telemetry for a Load Resource that is not a Controllable Load Resource continuously and accurately represents the amount of Load Resource that has been restored following a recall instruction and is available for subsequent deployment.

If Non-Spin has been deployed in the Houston area to help manage the N_H Voltage Stability Limit, the deployments will be recalled once reliability margins have been restored to a manageable level.

4. Non-Spinning Reserve Service Deployment and Recall Procedure Revision Process

Revisions to the Non-Spinning Reserve Service Deployment and Recall Procedure shall be made according to the approval process as prescribed in Protocol Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment.

ERCOT Impact Analysis Report

OBDRR Number	<u>035</u>	**OBDRR Title**	**Related to NPRR1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve**
Impact Analysis Date	November 8, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Other Binding Document Revision Request (OBDRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1101, Create Non-Spin Deployment Groups made up of Generation Resources Providing Off-Line Non-Spinning Reserve and Load Resources that are Not Controllable Load Resources Providing Non-Spinning Reserve. See Comments		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this OBDRR beyond what was captured in the Impact Analysis for NPRR1101.

Board Report

OBDRR Number	<u>036</u>	**OBDRR Title**	**Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to implement revisions to the Emergency Response Service (ERS) deployment process in time for the winter season.		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)		
Priority and Rank Assigned	Not Applicable		
Other Binding Document Requiring Revision	Emergency Response Service Procurement Methodology		
Supporting Protocol or Guide Section(s) / Related Documents	NPRR1106 Nodal Operating Guide Revision Request (NOGRR) 237, Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA) Nodal Operating Guide Section 4.5.3.3, EEA Levels ERCOT Operating Procedures – Real-Time Desk ERCOT Operating Procedures – Resource Desk ERCOT Operating Procedures – Scripts Emergency Response Service Technical Requirements & Scope of Work		
Revision Description	This Other Binding Document Revision Request (OBDRR) revises the Emergency Response Service Procurement Methodology to state that ERCOT will make an initial allocation of the annual expenditure limit to each ERS Time Period in each ERS Standard Contract Term based on the expected risk of deploying ERS in that ERS Time Period, to remove outdated language pertaining to the ERS offer cap and its relationship to historical prices paid to the Transmission and/or Distribution Service Provider (TDSP) Load management programs, and to include language to clarify that ERCOT has discretion to revise and re-issue Requests for Proposal (RFPs) prior to the offer submission deadline.		

Board Report

Reason for Revision	☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☒ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	This OBDRR proposes revisions necessary to implement changes proposed in NPRR1106 pursuant to Public Utility Commission of Texas (PUCT) Docket No. 52373, Review of Wholesale Electric Market Design, wherein PUCT Staff filed a Motion for Good Cause Exception that requested the PUCT grant ERCOT a good cause exception pursuant to P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), "so that ERCOT may procure ERS that may be used prior to the declaration of an EEA, rather than being limited to use of the ERS during an EEA, as allowed by 16 TAC § 25.507(a)." The PUCT voted to grant this exception at its October 28, 2021 Open Meeting.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of OBDRR036 as submitted, and the Impact Analysis for OBDRR036. There was one opposing vote from the Independent Power Marketer (IPM) (Morgan Stanley) Market Segment, and one abstention from the Municipal (Garland) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the Impact Analysis, ERCOT Opinion, and ERCOT Market Impact Statement for OBDRR036.
ERCOT Opinion	ERCOT supports approval of OBDRR036.
ERCOT Market Impact Statement	ERCOT Staff has reviewed OBDRR036 and believes the market impact for OBDRR036 enhances ERCOT's operational tools to address potential reliability outcomes by granting ERCOT Operators the discretion to deploy ERS when Physical Responsive Capability (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-Spinning Reserve (Non-Spin).
Board Decision	On 12/10/21, the ERCOT Board recommended approval of

	OBDRR036 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
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Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Please note the baseline Other Binding Document language has been updated to reflect the incorporation of the following OBDRR(s):

- OBDRR023, Related to NPRR984, Change ERS Standard Contract Terms (unboxed 12/1/21)

Proposed Other Binding Document Language Revision

EMERGENCY RESPONSE SERVICE

Procurement Methodology

ERCOT Board approved TBD

Effective Date of TBD

Date Approved	Version	Description	Author(s)	Approved By	Effective Date
11/19/13	0.1	ERCOT Board approved NPRR564, Thirty-Minute Emergency Response Service (ERS) and Other ERS Revisions, and associated OBD, Emergency Response Service Procurement Methodology	ERCOT	ERCOT Board	11/20/13
4/8/14	0.2	Revised Section G, Clearing Price. Language grey boxed until effective date of 5/1/14. **<u>History:</u>** • 3/11/14 – Notification of proposed revisions • 3/27/14 – TAC recommended approval • 4/8/14 – ERCOT Board of Directors approved • 5/1/14 – Removed grey box from Section G	ERCOT	ERCOT Board	5/1/14
10/14/14	0.3	Revised Section G, Clearing Price. (Associated NPRR637, Clarification of ERS Language and ERCOT Process for Co-located Resources.) Language grey boxed until effective date of 11/1/14. **<u>History:</u>** • 8/21/14 – Notification of proposed revisions • 8/28/14 – TAC recommended approval • 10/14/14 – ERCOT Board of Directors approved • 11/1/14 – Removed grey box from Section G	ERCOT	ERCOT Board	11/1/14
6/12/18	0.4	Revisions proposed by OBDRR004, Updates to Emergency Response Service Procurement Methodology	ERCOT	ERCOT Board	7/1/18
10/13/20	0.5	Revisions proposed by OBDRR023, Related to NPRR984, Change ERS Standard Contract Terms. Language grey boxed until effective date of 2/1/21 and upon system implementation of NPRR984 **<u>History:</u>** • 8/5/20 – Notification of proposed revisions • 8/26/20 – TAC recommended approval • 10/13/20 – ERCOT Board of	ERCOT	ERCOT Board	2/1/21

Date Approved	Version	Description	Author(s)	Approved By	Effective Date
		Directors approved • 2/1/21 – Unboxed footnote in Section E; • 10/1/21 – Unboxed remaining language due to system implementation of NPRR984; • 12/1/21 – Removed footnote in Section E			
4/13/21	0.6	Revisions proposed by OBDRR027, Clarify Implementation Timeline for OBDRR023 (changed effective date of OBDRR023) **History:** • 2/2/21 – Notification of proposed revisions • 3/24/21 – TAC recommended approval • 4/13/21 – ERCOT Board of Directors approved	ERCOT	ERCOT Board	4/16/21

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Board Report

Electric Reliability Council of Texas, Inc. (ERCOT) administers Emergency Response Service (ERS) in accordance with Public Utility Commission of Texas (PUCT) Substantive Rule §25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS)[1] and the ERCOT Nodal Protocols. This document is intended to be consistent with these standards, but to the extent any conflict exists, the PUC Rule or Protocols control.

[1] http://www.puc.state.tx.us/agency/rulesnlaws/subrules/electric/25.507/25.507ei.aspx

Board Report

A. DOCUMENT DESCRIPTION

This document describes the mechanism for procuring ERS and is considered an "Other Binding Document," as that term is defined in the ERCOT Protocols.

B. CHANGE CONTROL PROCESS

ERCOT Staff will provide a period for stakeholder review and comment for proposed revisions to this document as follows:

(1) ERCOT shall post proposed revisions to the Emergency Response Service Procurement Methodology to the ERCOT website.

(2) ERCOT shall also electronically notify stakeholders of the proposed revisions via the TAC and Others distribution list and define the comment period which shall be at least 14 days after initial posting.

(3) To receive consideration, comments should be submitted via email to ERS@ercot.com by the deadline set forth in the notification.

(4) Upon Market Participant written request, ERCOT will conduct a conference call and online review of the submitted comments.

(5) ERCOT will review proposed document revisions with the Technical Advisory Committee (TAC).

(6) ERCOT will submit proposed document revisions for ERCOT Board approval.

(7) Within three Business Days of ERCOT Board approval, ERCOT shall post the revised document to the ERCOT website.

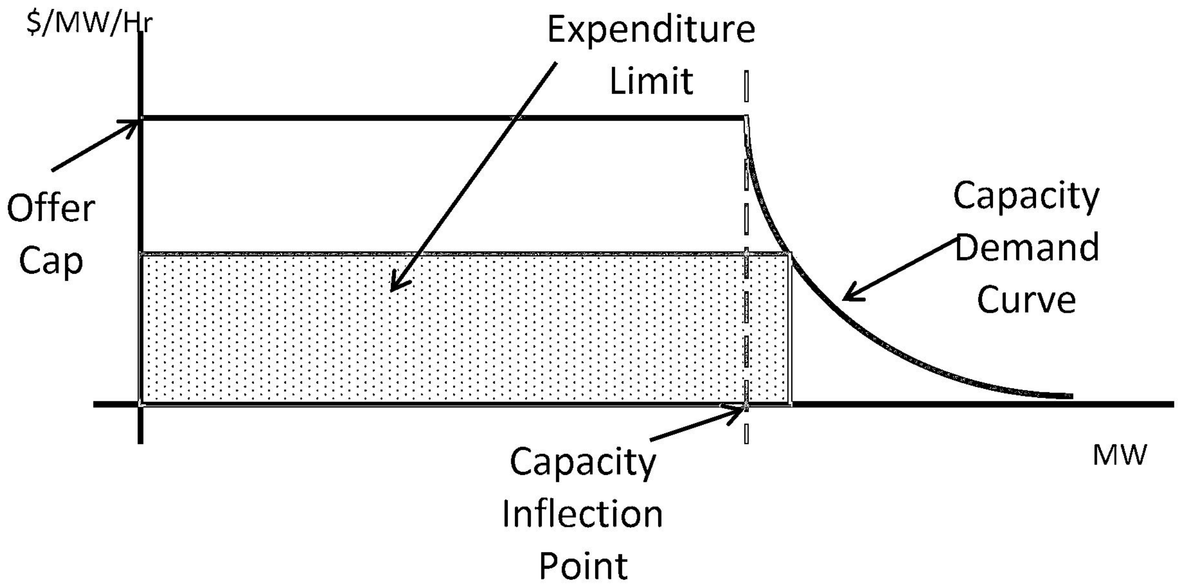
C. ERS Capacity Demand Curve

ERCOT will develop a capacity demand curve for each ERS Time Period, and all ERS products will be procured together within the limits of that curve. ERCOT shall maximize the MW procured subject to the expenditure limit for the relevant Time Period. Each demand curve is derived from the three following parameters, which ERCOT will specify in the Request for Proposal (RFP) for ERS procurement:

(1) ERS Offer Cap

(2) ERS Time Period Capacity Inflection Point

(3) ERS Time Period Expenditure Limit



D. ERS Offer Cap

The ERS offer cap establishes a maximum possible procurement price of $80/MW/hr for every ERS Time Period during the ERS budget year. ERCOT will automatically reject any offers above the offer cap.

E. ERS Expenditure Limit

P.U.C. Substantive Rule 25.507 restricts ERCOT's ERS expenditures to an annual cost cap of $50 million. ERCOT will allocate the $50 million available expenditure within its ERS budget year, which starts with the December through March Standard Contract Term and ends with the October through November Standard Contract Term.

No later than 60 days before each new ERS budget year, ERCOT will make an initial allocation of the annual expenditure limit to each ERS Time Period in each ERS Standard Contract Term based on the expected risk of deploying ERS in that ERS Time Period, in accordance with the formula detailed below. ERCOT will assign a high (H), moderate (M), or low (L) risk designation to each ERS Time Period and will assign a risk-weighting factor (a value from 1 to 100 with 1 being the lowest risk value and 100 being the highest risk value) for each risk designation. ERCOT's risk assessment will consider a number of factors, including, but not limited to, forecasted operating reserves, forecasted Load, and Resource outage information.

Prior to issuing an RFP for an upcoming Standard Contract Term, ERCOT will update the ERS Time Period Expenditure Limits for each remaining ERS Time Period in the budget year to reflect updated forecasts and any expected remaining funds from ERS Standard Contract Terms within the same ERS budget year. Unless the offer submission deadline for the upcoming Standard Contract Term has passed, ERCOT may update the ERS Time Period Expenditure Limits and issue a revised RFP if funds originally allocated to the upcoming Standard Contract Term must be reallocated to fund an ERS renewal Contract Period in the current Standard Contract Term. ERCOT may revise and reissue the RFP for other reasons if the offer submission date has not yet passed. Any funds remaining at the end of an ERS budget year will not be carried forward into a new ERS budget year.

For each ERS Time Period, the expenditure limit is calculated as follows:

$$Expenditure\ Limit_{TP} = Annual\ Expenditure\ Limit\ Remaining_{Program\ Year} \times \begin{matrix} Expenditure \\ Limit \\ Allocation \\ Factor \end{matrix}_{TP}$$

Where

$$\begin{matrix} Expenditure \\ Limit \\ Allocation \\ Factor \end{matrix}_{TP} = \left[\begin{matrix} Risk \\ Weighting \\ Factor \end{matrix}_{TP} \times \#\ hrs_{TP} \times OfferCap \right] \div \left[\sum_{TP} \begin{matrix} Risk \\ Weighting \\ Factor \end{matrix}_{TP} \times \#\ hrs_{TP} \times OfferCap \right]$$

F. Capacity Inflection Point

The capacity inflection point establishes the point on the capacity demand curve where capacity can only be procured at an offer price less than the ERS Time Period offer cap while respecting the expenditure limit for that ERS Time Period. The capacity inflection point for each time period is calculated as follows:

$$CapInflectionPoint_{TP} = ExpenditureLimit_{TP} \div [\#\ hrs_{TP} \times OfferCap]$$

Table A below provides hypothetical calculations of the expenditure limits and capacity inflection point for each ERS Time Period in each budget year.

Standard Contract Term	Time Period	Risk Level	Risk Weighting Factor (a)	Time Period Hours (b)	Offer Cap (c)	(a)*(b)*(c)	Expenditure Limit Allocation Factor	ERS Time Period Expenditure Limit	Capacity Inflection Point (MW)
DecMar	TP1	H	80	332	$ 80	2,124,800	15.63%	7,813,373	294.2
	TP2	M	30	332	$ 80	796,800	5.86%	2,930,015	110.3
	TP3	L	1	249	$ 80	19,920	0.15%	73,250	3.7
	TP4	H	80	249	$ 80	1,593,600	11.72%	5,860,030	294.2
	TP5	M	50	249	$ 80	996,000	7.33%	3,662,519	183.9
	TP6	M	40	152	$ 80	486,400	3.58%	1,788,604	147.1
	TP7	L	20	228	$ 80	364,800	2.68%	1,341,453	73.5
	TP8	L	1	1,112	$ 80	88,960	0.65%	327,126	3.7
AprMay	TP1	M	60	168	$ 80	806,400	5.93%	2,965,316	220.6
	TP2	L	1	168	$ 80	13,440	0.10%	49,422	3.7
	TP3	L	1	126	$ 80	10,080	0.07%	37,066	3.7
	TP4	L	1	126	$ 80	10,080	0.07%	37,066	3.7
	TP5	M	60	126	$ 80	604,800	4.45%	2,223,987	220.6
	TP6	L	1	76	$ 80	6,080	0.04%	22,358	3.7
	TP7	L	1	114	$ 80	9,120	0.07%	33,536	3.7
	TP8	L	1	560	$ 80	44,800	0.33%	164,740	3.7
JunSep	TP1	L	10	344	$ 80	275,200	2.02%	1,011,973	36.8
	TP2	L	10	344	$ 80	275,200	2.02%	1,011,973	36.8
	TP3	H	100	258	$ 80	2,064,000	15.18%	7,589,798	367.7
	TP4	H	100	258	$ 80	2,064,000	15.18%	7,589,798	367.7
	TP5	L	10	258	$ 80	206,400	1.52%	758,980	36.8
	TP6	L	1	144	$ 80	11,520	0.08%	42,362	3.7
	TP7	L	1	216	$ 80	17,280	0.13%	63,542	3.7
	TP8	L	1	1106	$ 80	88,480	0.65%	325,361	3.7
OctNov	TP1	L	10	164	$ 80	131,200	0.96%	482,452	36.8
	TP2	L	10	164	$ 80	131,200	0.96%	482,452	36.8
	TP3	L	10	123	$ 80	98,400	0.72%	361,839	36.8
	TP4	L	10	123	$ 80	98,400	0.72%	361,839	36.8
	TP5	L	10	123	$ 80	98,400	0.72%	361,839	36.8
	TP6	L	1	80	$ 80	6,400	0.05%	23,534	3.7
	TP7	L	1	120	$ 80	9,600	0.07%	35,301	3.7
	TP8	L	1	568	$ 80	45,440	0.33%	167,093	3.7

Table A. ERS Time Period Expenditure Limit Allocation and Capacity Inflection Point Calculations

G. Clearing Price

The highest offer accepted for an ERS Time Period from will set the clearing price for all ERS Resources cleared in that ERS Time Period. All ERS service types specified in the Protocols will be procured using a common ERS capacity demand curve for each ERS Time Period and the highest offer accepted for an ERS Time Period will set the clearing price for all ERS service types.

If the procurement of all offers at the same price for an ERS Time Period would exceed the ERS Expenditure Limit for that ERS Time Period, ERCOT shall consider each such offer in an order established at random.

If awarding an offer would not exceed the ERS Expenditure Limit that offer will be awarded for the full capacity offered.

If awarding an offer for the full amount of the offered capacity would exceed the ERS Expenditure Limit, the following steps will be taken:

(1) If awarding an offer for the full amount of the offered capacity would exceed the ERS Expenditure Limit, the following steps will be taken: If the QSE has indicated on its offer that capacity proration is not allowed for that ERS Resource, the offer will be rejected.

(2) If the QSE has indicated on its offer that capacity proration is allowed for that ERS Resource, and if the capacity following proration is greater than or equal to the Proration Lower Limit specified on the offer, the offer will be accepted and the prorated capacity will be awarded.

(3) If the QSE has indicated on its offer that capacity proration is allowed by the QSE for that ERS Resource, and if the prorated capacity is less than the Proration Lower Limit specified on the offer, the offer will be rejected.

H. ERS Capacity provided through ERS Self Provision

For any ERS self-provision, ERCOT will reduce the Time Period expenditure limit for any offers to self-provide part or all of a QSE's ERS Obligation by the clearing price for ERS.

ERCOT Impact Analysis Report

OBDRR Number	<u>036</u>	OBDRR Title	Related to NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
Impact Analysis Date	November 19, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Other Binding Document Revision Request (OBDRR) can take effect upon system implementation of NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA).		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this OBDRR beyond what was captured in the Impact Analysis for NPRR1106.

Board Report

PGRR Number	**092**	**PGRR Title**	**Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation of Nodal Protocol Revision Request (NPRR) 1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs		
Priority and Rank Assigned	Not Applicable		
Planning Guide Sections Requiring Revision	5.2.3, Self-Limiting Facilities		
Related Documents Requiring Revision/Related Revision Requests	NPRR1077 Resource Registration Glossary Revision Request (RRGRR) 029, Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs		
Revision Description	This Planning Guide Revision Request (PGRR) allows an Interconnecting Entity (IE) proposing a Settlement Only Generator (SOG) to designate that SOG as part of a Self-Limiting Facility for the purposes of the Generator Interconnection or Modification (GIM) process. The PGRR is consistent with NPRR1077, which broadens the Self-Limiting Facility concept in the Protocols to allow SOGs to be designated as part of a Self-Limiting Facility.		
Reason for Revision	☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements		

Board Report

	☐ Other: (explain) *(please select all that apply)*
Business Case	Developers have expressed interest in siting multiple SOGs at the same sites without altering the inverter rating. This PGRR enables these additions by clarifying that the studies and tests conducted as part of the interconnection process for such a capacity addition, when designated as part of a Self-Limiting Facility, will consider only the amount of the maximum MW Injection, and if appropriate, the maximum MW Withdrawal, and not necessarily the gross amount of capacity added.
ROS Decision	On 6/3/21, ROS voted unanimously via roll call to table PGRR092 and refer the issue to the Operations Working Group (OWG) and Planning Working Group (PLWG). All Market Segments participated in the vote. On 9/2/21 ROS voted unanimously via roll call to recommend approval of PGRR092 as submitted. All Market Segments participated in the vote. On 10/7/21, ROS voted unanimously via roll call to endorse and forward to TAC the 9/2/21 ROS Report and the Impact Analysis for PGRR092. All Market Segments participated in the vote.
Summary of ROS Discussion	On 6/3/21, there was no discussion. On 9/2/21, there was no discussion. On 10/7/21, participants reviewed the Impact Analysis.
TAC Decision	On 11/29/21, TAC voted unanimously via roll call to recommend approval of PGRR092 as recommended by ROS in the 11/17/21 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for PGRR092.
ERCOT Opinion	ERCOT supports approval of PGRR092.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR092 and believe PGRR92 enables the siting of multiple SOGs without altering inverter ratings by clarifying studies and tests conducted as part of the interconnection process.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of PGRR092 as recommended by TAC in the 11/29/21 TAC Report.

Board Report

Sponsor	
Name	Bill Blevins / Clayton Stice
E-mail Address	Bill.Blevins@ercot.com / Clayton.Stice@ercot.com
Company	ERCOT
Phone Number	512-248-6691 / 512-248-6806
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com mailto:Jordan.Troublefield@ercot.com
Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

[PGRR081: Insert Section 5.2.3 below upon system implementation of NPRR1026:]

5.2.3 Self-Limiting Facilities

(1) An Interconnecting Entity may elect to designate any proposed new or modified Generation Resource, Energy Storage Resource (ESR), or Settlement Only Generator (SOG) as a component of a Self-Limiting Facility for the purposes of the GIM process. Upon such designation, all studies and tests undertaken pursuant to this Section 5 or that may otherwise be required as a condition for interconnection shall use the Self-Limiting Facility's proposed MW Injection limit as the maximum potential injection to the ERCOT System, and, if applicable, shall use the Self-Limiting Facility's MW Withdrawal limit as

the maximum potential withdrawal from the ERCOT System, notwithstanding the nameplate capacity values provided.

(2) Any Generation Resource, ESR, or SOG that has been studied and tested in the GIM process as a component of a Self-Limiting Facility may not, at any time during or after this process, increase the MW Injection limit or MW Withdrawal limit of the Self-Limiting Facility beyond the value or values that were used in these studies and tests without re-initiating the GIM process to evaluate the impacts of the increased value or values.

ERCOT Impact Analysis Report

PGRR Number	**092**	**PGRR Title**	**Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs**
Impact Analysis Date	May 19, 2021		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Planning Guide Revision Request (PGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOG) and Telemetry Requirements for SOGs.		
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 PGRR beyond what was captured in the Impact Analysis for NPRR1077.

Board Report

RRGRR Number	**029**	**RRGRR Title**	**Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Normal		
Proposed Effective Date	Upon system implementation of Nodal Protocol Revision Request (NPRR) 1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs		
Priority and Rank Assigned	Not Applicable		
Resource Registration Glossary Sections Requiring Revision	Section 2, Resource Registration Glossary – Unit Information Section 2, Resource Registration Glossary – Parameters		
Related Documents Requiring Revision/Related Revision Requests	NPRR1077 Planning Guide Revision Request (PGRR) 092, Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs		
Revision Description	This Resource Registration Glossary Revision Request (RRGRR) allows an Interconnecting Entity (IE) proposing a Settlement Only Generator (SOG) to designate that SOG as part of a Self-Limiting Facility for the purposes of the Generator Interconnection or Modification (GIM) process and provide that information using the same fields that RRGRR023, Related to NPRR1002, BESTF-5 Energy Storage Resource Single Model Registration and Charging Restrictions in Emergency Conditions, introduced for that purpose. The RRGRR is consistent with NPRR1077, which broadens the Self-Limiting Facility concept in the Protocols to allow SOGs to be designated as part of a Self-Limiting Facility.		
Reason for Revision	[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative		

Board Report

	☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	Developers have expressed interest in siting multiple SOGs at the same site without altering the inverter rating. This RRGRR provides a new data field so that ERCOT systems (Market Management System (MMS), Energy Management System (EMS), etc.) can be designated as part of a Self-Limiting Facility, as well as identify the amount of the maximum MW Injection, and if appropriate, the maximum MW Withdrawal, in addition to the nameplate amount of capacity added.
ROS Decision	On 6/3/21, ROS voted unanimously via roll call to table RRGRR029 and refer the issue to the Operations Working Group (OWG) and Planning Working Group (PLWG). All Market Segments participated in the vote. On 9/2/21, ROS voted unanimously via roll call to recommend approval of RRGRR029 as submitted. All Market Segments participated in the vote. On 10/7/21, ROS voted unanimously via roll call to endorse and forward to TAC the 9/2/21 ROS Report and the Impact Analysis for RRGRR029. All Market Segments participated in the vote.
Summary of ROS Discussion	On 6/3/21, there was no discussion. On 9/2/21, there was no discussion. On 10/7/21, participants reviewed the Impact Analysis.
TAC Decision	On 11/29/21, TAC voted unanimously via roll call to recommend approval of RRGRR029 as recommended by ROS in the 11/17/21 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the ERCOT Opinion and ERCOT Market Impact Statement for RRGRR029.
ERCOT Opinion	ERCOT supports approval of RRGRR029.
ERCOT Market Impact Statement	ERCOT Staff has reviewed RRGRR029 and believes the market impact of RRGRR029 will allow an IE proposing an SOG to designate that SOG as part of a Self-Limiting Facility, and ERCOT systems to identify the amount of the maximum MW Injection, the maximum MW Withdrawal, in addition to the nameplate amount of capacity added.

Board Report

Board Decision	On 12/10/21, the ERCOT Board recommended approval of RRGRR029 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Bill Blevins / Clayton Stice
E-mail Address	Bill.Blevins@ercot.com / Clayton.Stice@ercot.com
Company	ERCOT
Phone Number	512-248-6691 / 512-248-6806
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Brittney Albracht
E-Mail Address	Brittney.Albracht@ercot.com
Phone Number	512-225-7027

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Please note that administrative revisions have been made to the language below and authored as "ERCOT Market Rules".

Please note the baseline language in the following section(s) has been updated to reflect the incorporation of the following RRGRR(s) into the Resource Registration Glossary:

- RRGRR025, Related to NPRR1005, Clarify Definition of Point of Interconnection (POI) and Add Definition Point of Interconnection Bus (POIB) (incorporated 9/1/21)
    - Section 2, Resource Registration Glossary – Unit Information
- RRGRR031, Related to NPRR995, RTF-6 Create Definition and Terms for Settlement Only Energy Storage (incorporated 11/1/21)
    - Section 2, Resource Registration Glossary – Unit Information
    - Section 2, Resource Registration Glossary – Parameters

Proposed Guide Language Revision

SECTION 2: RESOURCE REGISTRATION GLOSSARY - Effective November 1, 2021																
Resource Registration Data	Wind	Solar Photovoltaic (PV)	[RRGRR023 and RRGRR031: Insert applicable portions of column "Energy Storage	Conventional Generation (Gen)	Combined Cycle (CC)	Load Resources	Distributed Generation	Notes	Field Name	Definition / Detailed Description	Screening Study (SS) (R, C, O, A)	Full Interconnect Study (FIS) (R, C, O, A)	FIS - Stability Study (R, C, O, A)	Planning Model (R, C, O, A)	Full Registration (R, C, O, A)	
Unit Information																
Unit Information	X	X	X	X	-		X	-	Resource Site Code:	Enter the Site Code established in the General and Site Information tab of the GENERAL_SITE_ESIID_Information workbook.	R	R	R	R	R	
Unit Information	X	X	X	X	X		X	All Caps	UNIT NAME	Enter Unit Code for the generator unit (e.g. Cedar Bayou Plant Gen 1 is "CBYG1").	R	R	R	R	R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Unit Information - UNIT NAME" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Unit Information	X	X	X	X	X		X	All Caps	UNIT NAME	Enter Unit Code for the generator unit (e.g. Cedar Bayou Plant Gen 1 is "CBYG1"). For an ESS this is the name of the ESS while discharging.	R	R	R	R	R	
Unit Information	X	X	X	X	X		X	Automatic	Resource Name (Unit Code/Mnemonic)	Concatenated mnemonic of Resource Site Code and Unit name (e.g. CBY_CBYG1).				A	A	
[RRGRR023 and RRGRR031: Insert applicable portions of "Unit Information" rows below upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																

Unit Information			X					All Caps	Energy Storage System (ESS) Name	This name is used to tie ESS discharging and charging, prior to single ESS model era.	R	R	R	R	R	
Unit Information			X					All Caps	Dispatch Asset Code (provided by ERCOT)	For ESS enter the Dispatch Asset Code (this code will be provided by ERCOT). This code will be used for the ESS while charging.					R	
Unit Information			X		-				ESIID assigned to meter	ESI ID number assigned to the meter. For NOIEs, the TDSP will create a non-settlement ESI ID.					R	
Unit Information			X		-			Y/N	Wholesale Delivery Point?	Enter Y or N, if the point of delivery is a wholesale delivery point.					R	
Unit Information	X	X	X	X	-			Y/N	Settlement Only Generator (SOG)	Refer to ERCOT Protocol Section 2.1, Definitions, for the definition of a Settlement Only Generator (SOG).				R	R	
[RRGRR031: Replace "Unit Information - Settlement Only Generator (SOG)" above upon system implementation of NPRR995:]																
Unit Information	X	X	X	X				Y/N	Settlement Only Generator (SOG) or Settlement Only Energy Storage System (SOESS)	Refer to ERCOT Protocol Section 2.1, Definitions, for the definition of a Settlement Only Generator (SOG) and Settlement Only Energy Storage System (SOESS).				R	R	
Unit Information	X	X	X	X	-			-	PUC Registration Number	Enter the PUCT registration number.					O	
[RRGRR023: Insert "Unit Information" rows below upon system implementation of NPRRs 1002, 1026, and 1029:]																
Unit Information	X	X	X					Y/N	DC-Coupled Resource	Refer to ERCOT Protocol Section 2.1, Definitions, for the definition of a DC-Coupled Resource	R	R	R	R	R	
Unit Information			X				X	Y/N	Self-Limiting Resource or Settlement Only Generator	Refer to ERCOT Protocol Section 2.1, Definitions, for the definition of a Self-	R	R	R	R	R	

										Limiting Resource						
Unit Information	X	X	X	X	X		X	Y/N	Part of Self-Limiting Resource Facility	Refer to ERCOT Protocol Section 2.1, Definitions, for the definition of a Self-Limiting Resource Facility	R	R	R	R	R	
Unit Information	X	X	X	X	X		X	#	Self-Limiting Facility #	Self-Limiting Facility # 1, 2, 3….Leave blank if not Self-Limiting Facility. Refer to definition of Self-Limiting Facility in Protocol Section 2.1, Definitions.	R	R	R	R	R	
Unit Information	X	X	X	X	X		X	Automatic	Site_Self-Limiting Facility#	Automatic field. All Resources that are part of the same Self-Limiting Facility will have same code					A	
Unit Information	X	X	X	X	X			-	ERCOT Interconnection Project Number - Only New Units	Enter the ERCOT INR number. Required for new or upgraded units.		C	C	C	C	
Unit Information	X	X	X	X	-			-	NERC Number	Enter NERC NCR number.					O	
Unit Information	X	X	X	X	-			Y/N	Qualifying Facility	Refer to ERCOT Protocol Section 2 for the definition of Qualifying Facility.					R	
Unit Information	X	X	X	X	X			mm/dd/yyyy	Transmission Only MRD	Proposed model load date for RE-owned transmission equipment.					O	
Unit Information	X	X	X	X	X			mm/dd/yyyy	Standard Generation Interconnection Agreement (SGIA) Signature Date	Enter the date the Resource signed SGIA. For NOIEs, use MOU date.					R	
Unit Information	X	X	X	X	X		X	mm/dd/yyyy	Unit Start Date (Model Ready Date)	Proposed model load date for unit. Required for new units only.					O	
Unit Information	X	X	X	X	X			mm/dd/yyyy	Commercial Operations Date	Enter the unit's planned Commercial Operations Date. After the unit	R	R	R	R	R	

										completes operational performance testing, this field should be updated by the RE with the actual Commercial Operations Date.						
Unit Information	X	X	X	X	X		X	mm/dd/yyyy	Unit End Date	Entry of a date in this field will result in the unit being removed from the ERCOT model. Enter the model ready date of expected or actual retirement. Leave blank if not known/applicable.					O	
Unit Information	X	X	X	X	X			All Caps	SubStation Code/SubStation Mnemonic	Enter the interconnecting transmission station code. If you need assistance in determining the corresponding ERCOT Substation Code\Mnemonic, please consult your TDSP, or ERCOT. For the SS/FIS, if a substation code cannot be identified, leave field blank and enter the expected electrical connection point as text in the comment section.	O	O	O	R	R	
Unit Information	X	X	X	X	X			kV	Voltage Level	Enter the nominal voltage level at the Point of Interconnection (e.g. 69kV, 138kV, 345kV). If you need assistance in determining the corresponding Voltage Level, please consult your TDSP, or ERCOT.	R	R	R	R	R	
[RRGRR025: Replace "Unit Information - Voltage Level" above with the following upon system implementation of NPRR1005:]																
Unit Informati	X	X	X	X	X			kV	Voltage Level	Enter the nominal voltage level at the Point of	R	R	R	R	R	

on										Interconnection Bus (e.g. 69kV, 138kV, 345kV). If you need assistance in determining the corresponding Voltage Level, please consult your TDSP, or ERCOT.						
Unit Information	X	X	X	X	X			#	PTI Bus Number	Enter the PTI Bus Number at the Point of Interconnection in the planning model. If you need assistance in determining the corresponding PTI Bus Number, please consult your TDSP, or ERCOT.	O	O	O	R	R	
[RRGRR025: Replace "Unit Information - PTI Bus Number" above with the following upon system implementation of NPRR1005:]																
Unit Information	X	X	X	X	X			#	PTI Bus Number	Enter the PTI Bus Number at the Point of Interconnection Bus in the planning model. If you need assistance in determining the corresponding PTI Bus Number, please consult your TDSP, or ERCOT.	O	O	O	R	R	
[RRGRR023 and RRGRR031: Insert applicable portions of "Unit Information - Transmission Station Load Name in Network Operations Model" below upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Unit Information			X					All Caps	Transmission Station Load Name in Network Operations Model	Enter the Load Name as listed in the ERCOT model as provided by the TDSP to be used by the ESS while charging.					R	
Unit Information	X	X	X	X	X		X	List	Primary Fuel Type	AB -- Agriculture Byproducts (bagasse, straw, energy crops) BFG -- Blast-Furnace Gas BIT -- Bituminous Coal BL -- Black liquor DFO -- Distillate Fuel Oil (diesel, No1 fuel oil, No 2	R	R	R	R	R	

										fuel oil, No 4 fuel oil) GEO -- Geothermal JF -- Jet Fuel KER -- Kerosene LFG -- Landfill Gas LIG -- Lignite MSW -- Municipal Solid Waste (refuse) NA -- Not Applicable NG -- Natural Gas (use this fuel type for steam turbines which are part of a Combined Cycle Train) NUC -- Nuclear (uranium, plutonium, thorium) OBG -- Other - Biomass Gas (methane, digester gas) OBL -- Other - Biomass Liquids (ethanol, fish oil, waste alcohol, other gases) OBS -- Other - Biomass Solids (animal manure/waster, medical waste, paper pellets, paper derived fuel) OG -- Other - Gas (butane, coal processes, coke-oven coal, methanol, refinery gas) OO -- Other - Oil (butane, crude, liquid byproducts, oil waste, propane) OTH -- Other (batteries, chemicals, hydrogen pitch sulfur, misc. technologies) PC -- Petroleum Coke PG -- Propane RFO -- Residual Fuel Oil (No 5 and No 6 fuel oil) STM -- Steam from other units						

										SLW -- Sludge Waste SUB -- Sub-bituminous Coal SUN -- Solar (photovoltaic, thermal) TDF -- Tires T -- Tidal WAT -- Water (conventional, pumped storage) WDL -- Wood/Wood Waste - Liquids (red liquor, sludge wood spent sulfite liquor, other liquors) WDS -- Wood/Wood Waste - Solids (peat, railroad ties, utility poles, wood chips, other solids) WH -- Waste heat WND -- Wind WOC -- Waste / Other Coal						
[RRGRR023: Replace "Unit Information - Primary Fuel Type" above with the following upon system implementation of NPRRs 1002, 1026, and 1029:]																
Unit Information	X	X	X	X	X		X	List	Primary Fuel Type	AB -- Agriculture Byproducts (bagasse, straw, energy crops) BFG -- Blast-Furnace Gas BIT -- Bituminous Coal BL -- Black liquor DFO -- Distillate Fuel Oil (diesel, No1 fuel oil, No 2 fuel oil, No 4 fuel oil) GEO -- Geothermal JF -- Jet Fuel KER -- Kerosene LFG -- Landfill Gas LIG -- Lignite MSW -- Municipal Solid Waste (refuse) MWH – Electricity (use this fuel type for battery energy storage)	R	R	R	R	R	

										NA -- Not Applicable NG -- Natural Gas (use this fuel type for steam turbines which are part of a Combined Cycle Train) NUC -- Nuclear (uranium, plutonium, thorium) OBG -- Other - Biomass Gas (methane, digester gas) OBL -- Other - Biomass Liquids (ethanol, fish oil, waste alcohol, other gases) OBS -- Other - Biomass Solids (animal manure/waster, medical waste, paper pellets, paper derived fuel) OG -- Other - Gas (butane, coal processes, coke-oven coal, methanol, refinery gas) OO -- Other - Oil (butane, crude, liquid byproducts, oil waste, propane) OTH -- Other (chemicals, hydrogen pitch sulfur, misc. technologies) PC -- Petroleum Coke PG -- Propane RFO -- Residual Fuel Oil (No 5 and No 6 fuel oil) STM -- Steam from other units SLW -- Sludge Waste SUB -- Sub-bituminous Coal SUN -- Solar (photovoltaic, thermal) or DC-Coupled Resources combining photovoltaic and battery energy storage TDF -- Tires							

										T -- Tidal WAT -- Water (conventional, pumped storage) WDL -- Wood/Wood Waste - Liquids (red liquor, sludge wood spent sulfite liquor, other liquors) WDS -- Wood/Wood Waste - Solids (peat, railroad ties, utility poles, wood chips, other solids) WH -- Waste heat WND -- Wind and DC-Coupled Resources combining wind and battery energy storage WOC -- Waste / Other Coal WND_SUN – DC-Coupled Resources combining wind, photovoltaic and battery energy storage						
Unit Information	X	X	X	X	X			List	Secondary Fuel Type	Same data entry elements as primary fuel type, but for secondary or start-up fuel.	R	R	R	R	R	
[RRGRR023: Replace "Unit Information - Secondary Fuel Type" above with the following upon system implementation of NPRRs 1002, 1026, and 1029:]																
Unit Information	X	X	X	X	X			List	Secondary Fuel Type	Same data entry elements as primary fuel type, but for secondary or start-up fuel. For DC-Coupled Resource use MWH	R	R	R	R	R	
Unit Information	X	X		X	-			List	Fuel Transportation Type	CV -- Conveyor PL -- Pipeline RR -- Railroad TK -- Truck NA -- Not Applicable					R	
Unit Information	X	X	X	X	-		X	List	Resource Category	Nuclear Hydro Coal and Lignite Combined Cycle ≤ 90 MW*				R	R	

										Combined Cycle > 90 MW* Gas Steam - Supercritical Boiler Gas Steam - Reheat Boiler Gas Steam - Non-reheat or Boiler without air-preheater Simple Cycle ≤ 90 MW Simple Cycle > 90 MW Diesel Renewable Reciprocating Engine Solar Power Storage Other						
[RRGRR023: Replace "Unit Information - Resource Category" above with the following upon system implementation of NPRRs 1002, 1026, and 1029:]																
Unit Information	X	X	X	X	-		X	List	Resource Category	Nuclear Hydro Coal and Lignite Combined Cycle ≤ 90 MW* Combined Cycle > 90 MW* Gas Steam - Supercritical Boiler Gas Steam - Reheat Boiler Gas Steam - Non-reheat or Boiler without air-preheater Simple Cycle ≤ 90 MW Simple Cycle > 90 MW Diesel Renewable Reciprocating Engine Solar Battery Energy Storage DC-Coupled Battery Energy Storage and Solar DC-Coupled Battery Energy Storage and Wind DC-Coupled Battery Energy Storage and Solar and Wind Other				R	R	

Unit Information	X	X		X	-		X	Y/N	Renewable	Indicate if the unit is a Renewable Energy Credit (REC) generator, as certified with the PUCT.					R	
Unit Information	X	X		X	-		X	Y/N	Renewable/Offset	REC offset generators that produce generation to cover offsets they have been approved to provide, as certified with the PUCT.					R	
Unit Information	X	X	X	X	X		X	List	Physical Unit Type	CA -- Combined cycle steam turbine part (includes steam part of integrated coal gasification combined cycle) CC -- Combined cycle total unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided) CE -- Compressed air energy storage CS -- Combined cycle single shaft (combustion turbine and steam turbine share a single generator) CT -- Combined cycle combustion/gas turbine part (includes comb. turbine part of integrated coal gasification combined cycle) FC -- Fuel Cell GT -- Simple-cycle Combustion (gas) turbine (includes jet engine design) HY -- Hydraulic turbine (includes turbines associated with delivery of water by pipeline) IC -- Internal combustion (diesel, piston) engine	R	R	R	R	R	

										NA -- Unknown at this time (planned units only) OT -- Other PS -- Hydraulic Turbine - Reversible (pumped storage) PV -- Photovoltaic ST -- Steam Turbine including nuclear, geothermal and solar. Does not include combined cycle. WT -- Wind Turbine						
[RRGRR023: Replace "Unit Information - Physical Unit Type" above with the following upon system implementation of NPRRs 1002, 1026, and 1029:]																
Unit Information	X	X	X	X	X		X	List	Physical Unit Type	BA – Battery Energy Storage BA-PV – DC-Coupled Battery Energy Storage and Photovoltaic BA-WT – DC-Coupled Battery Energy Storage and Wind Turbine BA-PV-WT – DC-Coupled Battery Energy Storage, Photovoltaic and Wind Turbine CA -- Combined cycle steam turbine part (includes steam part of integrated coal gasification combined cycle) CC -- Combined cycle total unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided) CE -- Compressed air energy storage CS -- Combined cycle single shaft (combustion turbine	R	R	R	R	R	

										and steam turbine share a single generator) CT -- Combined cycle combustion/gas turbine part (includes comb. turbine part of integrated coal gasification combined cycle) FC -- Fuel Cell GT -- Simple-cycle Combustion (gas) turbine (includes jet engine design) HY -- Hydraulic turbine (includes turbines associated with delivery of water by pipeline) IC -- Internal combustion (diesel, piston) engine NA -- Unknown at this time (planned units only) OT -- Other PS -- Hydraulic Turbine - Reversible (pumped storage) PV -- Photovoltaic ST -- Steam Turbine including nuclear, geothermal and solar. Does not include combined cycle. WT -- Wind Turbine						
Unit Information	X	X	X	X	X		X	MVA	Name Plate Rating	Manufacturer designed MVA Rating of this unit at its rated power factor (gross).	R	R	R	R	R	
Unit Information	X	X	X	X	X			MW	Real Power Rating	Manufacturer designed MW at rated power factor (gross).	R	R	R	R	R	
Unit Information	X	X	X	X	X			MVAR	Reactive Power Rating	Manufacturer designed MVAr at rated power factor (gross)	R	R	R	R	R	
Unit Informati	X	X		X	X			MW	Turbine Rating	Manufacturer designed MW of the turbine (gross)	C	C	C	R	C	

on																
Unit Information	X	X	X	X	X			kV	Unit Generating Voltage	Terminal voltage of generating unit, as modeled (typically equivalent to low side of GSU)	R	R	R	R	R	
Unit Information	X	X	X	X	X			-	Governor Droop Setting	The percent change in frequency that will cause generator output to change from no Load to full Load. (e.g. for 5%, use .05)					C	
Unit Information	X	X	X	X	X			Hz	Governor Dead-band	The range of deviations of system frequency (+/-) that produces no Primary Frequency Response.					R	
Unit Information	X	X	X	X	X			degree F	Design Max Ambient Temperature	This is the plant design maximum (high) air temperature.					O	
Unit Information	X	X	X	X	X			degree F	Design Min Ambient Temperature	This is the plant design minimum (low) air temperature.					O	
[RRGRR019 and RRGRR023: Insert applicable portions of "Unit Information - Switchable Generation Resource" below upon system implementation of RRGRR019 or NPRRs 1002, 1026, and 1029 respectively:]																
Unit Information	X	X	X	X	X			Y/N	Switchable Generation Resource	Is the unit able to switch between the ERCOT Control Area and a non-ERCOT Control Area?	R	R	R	R	R	
	Parameters															
Parameters		X	X		X			List	SITECODE	For Parameters - CFG - enter the Site Code established in the General and Site Information tab of the GENERAL_SITE_ESIID_Information workbook.				R	R	
Parameters		X			X			List	Train Code	For Parameters - CFG - enter the Train Code as provided on the Unit				R	R	

										Information Train tab. Select from drop-down list.						
Paramet ers		X			X			List	Configuration Code	For Parameters - CFG - enter the Concatenated code of the Train Code and the Configuration Number. Select from drop-down list.				R	R	
Paramet ers	X	X	X	X	X			List	UNIT NAME	Code for name of generator unit, as provided on the Unit Information tab.				R	R	
Paramet ers	X	X	X	X	X			Automatic	Resource Name (Unit Code/Mnemonic)	Concatenated mnemonic of Resource Site Code and Unit name (e.g. CBY_CBYG1).				A	A	
Paramet ers	X	X	X	X	X			MW	High Reasonability Limit	A theoretical value of net generation above which, the generator is not expected to operate under most conceivable conditions. This value is used by ERCOT market systems to validate COP submissions of HSL, telemetered HSL, and certain offers which may have been entered in error by the QSE. The HRL is also used in settlements to deconstruct prices at a CCT logical resource node.					R	
[RRGRR023: Replace "Parameters - High Reasonability Limit" above with the following upon system implementation of NPRRs 1002, 1026, and 1029:]																
Paramet ers	X	X	X	X	X			MW	High Reasonability Limit	A theoretical value of net generation above which, the generator is not expected to operate under most conceivable conditions. This value is used by ERCOT market systems to validate COP submissions					R	

										of HSL, telemetered HSL, and certain offers which may have been entered in error by the QSE. The HRL is also used in settlements to deconstruct prices at a CCT logical resource node. Self-Limiting Resources should use this field to enter the limit for maximum MW injection.						
[RRGRR023: Insert "Parameters - High Reasonability Limit, Self-Limiting Facility" below upon system implementation of NPRRs 1002, 1026, and 1029:]																
Parameters	X	X	X	X	X		X	MW	High Reasonability Limit, Self-Limiting Facility	Limit for maximum MW injection for Self-Limiting Facility above which the Self-Limiting Facility is not expected to operate. This field should not be used by Resources that are not part of Self-Limiting Facility.						
Parameters	X	X	X	X	X			MW	Low Reasonability Limit	A theoretical limit of net generation below which, the generator is not expected to operate under most conceivable conditions. This value is used by ERCOT market systems to validate COP submissions of LSL, telemetered LSL, and certain offers which may have been entered in error by the QSE.					R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Low Reasonability Limit" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Low Reasonability Limit	A theoretical limit of net generation below which, the generator is not expected to					R	

										operate under most conceivable conditions. For Energy Storage System (ESS) Low Reasonability limit is a negative value showing theoretical limit of net withdrawal/charging below which ESS is not expected to withdraw/charge. This value is used by ERCOT market systems to validate COP submissions of LSL, telemetered LSL, and certain offers which may have been entered in error by the QSE. Self-Limiting Resources should use this field to enter the limit for maximum MW withdrawal.						
[RRGRR023: Insert "Parameters - Low Reasonability Limit, Self-Limiting Facility" below upon system implementation of NPRRs 1002, 1026, and 1029:]																
Parameters	X	X	X	X	X		X	MW	Low Reasonability Limit, Self-Limiting Facility	Limit for maximum MW withdrawal of Self-Limiting Facility above which the Self-Limiting Facility is not expected to operate This field should not be used by Resources that are not part of Self-Limiting Facility						
Parameters	X	X	X	X	X			MW/min	High Reasonability Ramp Rate Limit	An "Out-of-Bounds" value chosen by the Resource Entity that represents the maximum magnitude of the values entered for the up and down ramp rates used by SCED. Used by ERCOT to alarm/reject data exceeding this value.					R	

Parameters	X	X	X	X	X			MW/min	Low Reasonability Ramp Rate Limit	An "Out-of-Bounds" value chosen by the Resource Entity that represents the minimum magnitude of the values entered for the up and down ramp rates used by SCED. Used by ERCOT to alarm/reject data below this value.					R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Sustainable Rating - Spring	Spring months are March, April, and May. Ambient conditions (dry bulb temperature) assumptions by ERCOT Weather Zone shall be as follows: - 87 deg F for Coastal Weather Zone, - 89 deg F for East Weather Zone, - 96 deg F for Far West Weather Zone, - 90 deg F for North Central Weather Zone, - 89 deg F for North Weather Zone, - 92 deg F for South Central Weather Zone, - 90 deg F for South Weather Zone, - 93 deg F for West Weather Zone. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.				R	R	
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Spring	Spring months are March, April, and May. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.				R	R	

[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Sustainable Rating - Spring" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Spring	Spring months are March, April, and May. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum withdrawal/charging.				R	R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Emergency Rating - Spring	Spring months are March, April, and May. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Spring	Spring months are March, April, and May. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Emergency Rating - Spring" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Spring	Spring months are March, April, and May. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum emergency withdrawal/charging.					R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Sustainable Rating - Summer	Summer months are June, July, and August. Ambient conditions (dry bulb temperature) assumptions by ERCOT Weather Zone shall be as follows: - 94 deg F for Coastal				R	R	

										Weather Zone, - 98 deg F for East Weather Zone, - 98 deg F for Far West Weather Zone, - 101 deg F for North Central Weather Zone, - 99 deg F for North Weather Zone, - 99 deg F for South Central Weather Zone, - 96 deg F for South Weather Zone, - 99 deg F for West Weather Zone. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.						
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Summer	Summer months are June, July, and August. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.				R	R	
[RRGRR023 and RRGRR031: Replace "Parameters - Seasonal Net Min Sustainable Rating - Summer" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Summer	Summer months are June, July, and August. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum withdrawal/charging.				R	R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Emergency Rating - Summer	Summer months are June, July, and August. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	

Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Summer	Summer months are June, July, and August. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Emergency Rating - Summer" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Summer	Summer months are June, July, and August. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum emergency withdrawal/charging.					R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Sustainable Rating - Fall	Fall months are September, October, and November. Ambient conditions (dry bulb temperature) assumptions by ERCOT Weather Zone shall be as follows: - 86 deg F for Coastal Weather Zone, - 86 deg F for East Weather Zone, - 87 deg F for Far West Weather Zone, - 87 deg F for North Central Weather Zone, - 84 deg F for North Weather Zone, - 88 deg F for South Central Weather Zone, - 88 deg F for South Weather Zone, - 86 deg F for West Weather Zone. These are not the HSL/LSL or HEL/LEL values that are				R	R	

										submitted in the COP.						
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Fall	Fall months are September, October, and November. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.				R	R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Sustainable Rating - Fall" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Fall	Fall months are September, October, and November. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum withdrawal/charging.				R	R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Sustainable Rating - Fall	Fall months are September, October, and November. Ambient conditions (dry bulb temperature) assumptions by ERCOT Weather Zone shall be as follows: - 86 deg F for Coastal Weather Zone, - 86 deg F for East Weather Zone, - 87 deg F for Far West Weather Zone, - 87 deg F for North Central Weather Zone, - 84 deg F for North Weather Zone, - 88 deg F for South Central Weather Zone, - 88 deg F for South Weather Zone, - 86 deg F for West Weather				R	R	

										Zone. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.						
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Fall	Fall months are September, October, and November. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Emergency Rating - Fall" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Fall	Fall months are September, October, and November. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum emergency withdrawal/charging.					R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Sustainable Rating - Winter	Winter months are December, January, and February. Ambient conditions (dry bulb temperature) assumptions by ERCOT Weather Zone shall be as follows: - 37 deg F for Coastal Weather Zone, - 30 deg F for East Weather Zone, - 26 deg F for Far West Weather Zone, - 26 deg F for North Central Weather Zone, - 23 deg F for North Weather Zone, - 31 deg F for South Central Weather Zone, - 40 deg F for South				R	R	

										Weather Zone, - 26 deg F for West Weather Zone. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.						
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Winter	Winter months are December, January, and February. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.				R	R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Sustainable Rating - Winter" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Sustainable Rating - Winter	Winter months are December, January, and February. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum withdrawal/charging.				R	R	
Parameters	X	X	X	X	X			MW	Seasonal Net Max Emergency Rating - Winter	Winter months are December, January, and February. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating - Winter	Winter months are December, January, and February. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP.					R	
[RRGRR023 and RRGRR031: Replace applicable portions of "Parameters - Seasonal Net Min Emergency Rating - Winter" above with the following upon system implementation of NPRRs 1002, 1026, and 1029 for RRGRR023; or upon system implementation of NPRR995 for RRGRR031:]																
Parameters	X	X	X	X	X			MW	Seasonal Net Min Emergency Rating -	Winter months are December, January, and					R	

									Winter	February. These are not the HSL/LSL or HEL/LEL values that are submitted in the COP. For ESS this value is negative, showing seasonal net maximum emergency withdrawal/charging.						
Parameters				X				MW	MW1	Net MW value where the steam generator typically reaches rated pressure (required value for steam turbines).					C	
Parameters				X				PSI	PSI1	Rated throttle pressure (required value for steam turbines) at MW1					C	
Parameters				X				MW	MW2	Net unit output (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range enter the same value as is entered for MW1.					C	
Parameters				X				PSI	PSI2	Throttle steam pressure (psi) at MW2 value (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range enter the same value as is entered for PSI1.					C	
Parameters				X				MW	MW3	Net unit output (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range, or is not needed, enter the same value as is entered for MW2.					C	

Parameters				X				PSI	PSI3	Throttle steam pressure (psi) at MW3 value (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range, or is not needed, enter the same value as is entered for PSI2.					C	
Parameters				X				MW	MW4	Net unit output (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range, or is not needed, enter the same value as is entered for MW3.					C	
Parameters				X				PSI	PSI4	Throttle steam pressure (psi) at MW4 value (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range, or point is not needed, enter the same value as is entered for PSI3.					C	
Parameters				X				MW	MW5	Net unit output (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal operating range, or point is not needed, enter the same value as is entered for MW4.					C	
Parameters				X				PSI	PSI5	Throttle steam pressure (psi) at MW5 value (breakpoint value used to define the pressure/MW curve). If pressure is constant for the normal					C	

										operating range, or point is not needed, enter the same value as is entered for PSI4.						
Paramet ers				X				MW	MW6	Net unit MW output where the steam generator typically reaches minimum pressure (required value for steam turbines).					C	
Paramet ers				X				PSI	PSI6	Throttle steam pressure (psi) at MW6 value (required value for steam turbines).					C	
Paramet ers				X				PSIG/MW	Limiting K Factor	The K factor is used to model the stored energy available to the resource. The value ranges between 0.0 and 0.6 psig per MW change. Additional information on determining the K factor can be found in Attachment 2, Primary Frequency Response Reference Document, of NERC Reliability Standard, of BAL-001-TRE-1, Primary Frequency Response in the ERCOT Region. The default value would be zero (required for steam turbines).					C	

ERCOT Impact Analysis Report

RRGRR Number	**029**	**RRGRR Title**	**Related to NPRR1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs**
Impact Analysis Date		May 19, 2021	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Resource Registration Glossary Revision Request (RRGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1077, Extension of Self-Limiting Facility Concept to Settlement Only Generators (SOGs) and Telemetry Requirements for SOGs.	
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 RRGRR beyond what was captured in the Impact Analysis for NPRR1077.

Alignment Nodal Operating Guide Revision Request

NOGRR Number	<u>238</u>	**NOGRR Title**	**Alignment Changes for December 17, 2021 Nodal Operating Guide – NPRR1094, NPRR1105, NPRR1106**
Date Posted	December 10, 2021		
Status	Alignment Change		

Nodal Operating Guide Sections Requiring Revision	4.5.3.3, EEA Levels
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3 NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA) NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns Energy Emergency Alert (EEA) language in Section 4.5.3.3 with Protocols Section 6.5.9.4.2, EEA Levels. On December 10, 2021, the ERCOT Board approved NPRR1094, NPRR1105, and NPRR1106, all of which modified language in Protocols Section 6.5.9.4.2. Paragraph (6) of Section 1.3.1, Introduction, provides that ERCOT may make changes to the Nodal Operating Guide to maintain duplicate language between the Protocols and Nodal Operating Guide, and requires that Section 4.5.3.3 be modified only by an Alignment NOGRR.
Reason for Revision	☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the <u>ERCOT Strategic Plan</u> or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☒ Other: Alignment NOGRR *(please select all that apply)*

ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR238 and believes the market impact for NOGRR238 aligns the Nodal Operating Guide with current Protocols.

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Market Segment	Not Applicable

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Proposed Guide Language Revision

4.5.3.3 EEA Levels

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,300 MW and is not projected to be recovered above 2,300 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 1,750 MW:

(i) Request available Generation Resources, that can perform within the expected timeframe of the emergency, to come On-Line by initiating manual HRUC or through Dispatch Instructions;

(ii) Use available DC Tie import capacity that is not already being used;

(iii) Issue a Dispatch Instruction for Resources to remain On-Line which, before start of emergency, were scheduled to come Off-Line; and

(iv) Instruct QSEs to deploy undeployed Emergency Response Service (ERS)-10 and ERS-30.

[NOGRR221: Insert item (v) below upon system implementation of NPRR1010:]

(v) At ERCOT's discretion, manually deploy, through Inter-Control Center Communications Protocol (ICCP), available RRS and ERCOT Contingency Reserve Service (ECRS) capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

(i) Ensure COPs and telemetered High Sustained Limits (HSLs) are updated and reflect all Resource delays and limitations; and

[NOGRR221: Replace paragraph (i) above with the following upon system implementation of NPRR1010:]

(i) Ensure COPs and telemetered HSLs, Normal Ramp Rates, Emergency Ramp Rates, and Ancillary Service capabilities are updated and reflect all Resource delays and limitations; and

(ii) Suspend any ongoing ERCOT-required Resource performance testing.

[NOGRR216 and NOGRR229: Insert applicable portions of paragraph (iii) below upon system implementation of NPRR1002 for NOGRR216; or upon system implementation of NPRR995 for NOGRR229:]

(iii) Ensure that each of its ESRs and Settlement Only Energy Storage Systems (SOESSs) suspends charging until the EEA is recalled, except under the following circumstances:

(A) The ESR has a current SCED Base Point Instruction, Load Frequency Control Dispatch Instruction, or manual Dispatch Instruction to charge the ESR;

(B) The ESR or SOESS is actively providing Primary Frequency Response; or

(C) The ESR or SOESS is co-located behind a Point of Interconnection (POI) with onsite generation that is incapable of exporting additional power to the ERCOT System, in which case the ESR may continue to charge as long as maximum output to the ERCOT System is maintained.

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 1,750 MW and is not projected to be recovered above 1,750 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,430 MW:

(i) Instruct TSPs and Distribution Service Providers (DSPs) or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures that have not already been implemented. 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.

(ii) Instruct TSPs and DSPs to implement any available Load management plans to reduce Customer Load.

(iii) Instruct QSEs to deploy RRS supplied from Load Resources (controlled by high-set under-frequency relays). ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraph (iv) below.

[NOGRR186: Replace paragraph (iii) above with the following upon system implementation of NPRR863:]

(iii) Instruct QSEs to deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ECRS or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraph (iv) below.

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(iv) ERCOT shall deploy RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

[NOGRR186: Replace paragraph (iv) above with the following upon system implementation of NPRR863:]

(iv) Load Resources providing ECRS that are not controlled by high set under-frequency relays shall be deployed prior to Group 1 deployment. ERCOT shall deploy ECRS and RRS capacity supplied by Load Resources (controlled by high-set under-frequency relays) in accordance with the following:

(A) Instruct QSEs to deploy half of the RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 1 Load Resources providing RRS. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from Group 2 if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

[NOGRR186 and NOGRR198: Replace applicable portions of paragraph (A) above with the following upon system implementation of NPRR863 or NPRR939, respectively:]

(A) Instruct QSEs to deploy RRS with a Group 1 designation and all of the ECRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resources to interrupt Group 1 Load Resources providing ECRS and RRS. QSEs shall deploy Load Resources according to the group designation and will be given some discretion to deploy additional Load Resources from any of the groups not designated for deployment if Load Resource operational considerations require such. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy the remaining RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt Group 2 Load Resources providing RRS. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

[NOGRR198: Replace paragraph (B) above with the following upon system implementation of NPRR939:]

(B) At the discretion of the ERCOT Operator, instruct QSEs to deploy RRS that is supplied from Load Resources (controlled by high-set under-frequency relays) by instructing the QSE representing the specific Load Resource to interrupt additional Load Resources providing RRS based on their group designation. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period;

(C) The ERCOT Operator may deploy both of the groups of Load Resources providing RRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; and

[NOGRR186 and NOGRR198: Replace applicable portions of paragraph (C) above with the following upon system implementation of NPRR863 or NPRR939, respectively:]

(C) The ERCOT Operator may deploy Load Resources providing only ECRS (not controlled by high-set under-frequency relays) and all groups of Load Resources providing RRS and ECRS at the same time. ERCOT shall issue notification of the deployment via XML message. ERCOT shall follow this XML notification with a Hotline VDI, which shall initiate the ten-minute deployment period; and

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the Day-Ahead Reliability Unit Commitment (DRUC) for each QSE with a Load Resource obligation which may be deployed to interrupt under paragraph (A), Group 1 and paragraph (B), Group 2. ERCOT shall develop a process for determining which individual Load Resource to place in Group 1 and which to place in Group 2. ERCOT procedures shall select Group 1 and Group 2 based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

[NOGRR198 and NOGRR221: Replace applicable portions of paragraph (D) above with the following upon system implementation of NPRR939 or NPRR1010, respectively:]

(D) ERCOT shall post a list of Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource RRS or ECRS award, which may be deployed to interrupt under paragraph (A) and paragraph (B). ERCOT shall develop a process for determining which individual Load Resource to place in each group based on a random sampling of individual Load Resources. At ERCOT's discretion, ERCOT may deploy all Load Resources at any given time during EEA Level 2.

(vi) Unless a media appeal is already in effect, ERCOT shall issue an appeal through the public news media for voluntary energy conservation; and

(vii) With the approval of the affected non-ERCOT Control Area, TSPs, DSPs, or their agents may implement transmission voltage level BLTs, which transfer Load from the ERCOT Control Area to non-ERCOT Control Areas in accordance with BLTs as defined in the Operating Guides.

(b) Confidentiality requirements regarding transmission operations and system capacity information will be lifted, as needed to restore reliability.

(3) ERCOT may declare an EEA Level 3 when the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,430 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT will implement any measures associated with EEA Levels 1 and 2 that have not already been implemented.

[NOGRR216 and NOGRR229: Insert applicable portions of paragraph (a) below upon system implementation of NPRR1002 and renumber accordingly for NOGRR216; or upon system implementation of NPRR995 for NOGRR229:]

(a) ERCOT shall instruct ESRs and SOESSs to suspend charging. For ESRs, ERCOT shall issue the instruction via a SCED Base Point, or, if otherwise necessary, via a manual Dispatch instruction. An ESR or SOESS shall suspend charging unless providing Primary Frequency Response or LFC issues a charging instruction to an ESR that is carrying Regulation Down Service (Reg-Down). However, an ESR or SOESS co-located behind a POI with onsite generation that is incapable of exporting additional power to the ERCOT System may continue to charge as long as maximum output to the ERCOT System is maintained.

(a) When PRC falls below 1,000 MW and is not projected to be recovered above 1,000 MW within 30 minutes, or when the clock-minute average frequency falls below 59.91 Hz for 25 consecutive minutes, ERCOT shall direct all TOs to shed firm Load, in 100 MW blocks, distributed as documented in these Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,000 MW of PRC within 30 minutes.

(b) TOs and TDSPs may shed Load connected to under-frequency relays pursuant to an ERCOT Load shed directive issued during EEA Level 3 so long as each affected TO continues to comply with its Under-Frequency Load Shed (UFLS) obligation as described in Nodal Operating Guide Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation as described in Nodal Operating Guide Section 4.5.3.4, Load Shed Obligation.