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

The above parameter is defined as follows:

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

(h) Add the MW from DC Tie imports during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

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

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

(k) Subtract the MW from DC Tie import curtailments to address local transmission system limitations or emergency conditions in the receiving electric grid from GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the receiving grid operator. The MW subtracted from GTBD associated with any individual DC

Tie shall not exceed the higher of DC Tie advisory limit for imports on that tie as of 0600 in the Day-Ahead or subsequent advisory import limit minus the aggregate import on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.

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

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

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

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

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

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

(r) The Real-Time Reliability Deployment Price Adder for Energy is equal to the positive difference between the System Lambda from item (q) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(s) For each individual Ancillary Service, the Real-Time Reliability Deployment Price Adder for Ancillary Service is equal to the positive difference between the MCPC for that Ancillary Service from item (q) above and the MCPC for that Ancillary Service.

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

(1) ERCOT shall deploy Non-Spin Service by operator Dispatch Instruction for the portion of On-Line Generation Resources that is only available through power augmentation and participating as Off-Line Non-Spin, Off-Line Generation Resources and Load Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spin Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed RRS or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that scheduled on an individual Resource.

(2) Once Non-Spin capacity from Off-Line Generation Resources providing Non-Spin is deployed and the Generation Resources are On-Line, ERCOT shall use SCED to determine the amount of energy to be dispatched from those Resources.

(3) Off-Line Generation Resources providing Non-Spin (OFFNS Resource Status) are required to provide an Energy Offer Curve for use by SCED.

(4) Controllable Load Resources providing Non-Spin shall have an RTM Energy Bid for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource must comply with all requirements in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets."

[NPRR1093: Replace paragraph (4) above with the following upon system implementation:]

(4) Non-Spin can be provided by Controllable Load Resources that are SCED qualified or by Load Resources that are not Controllable Load Resources but do not have an under-frequency relay or the under-frequency relay is not armed.

(a) Controllable Load Resources providing Non-Spin shall have an RTM Energy Bid for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource must comply with all requirements in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets."

(b) Load Resources that are not Controllable Load Resources shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity. Following a deployment instruction, the QSE shall reduce the Non-Spin Ancillary Service Schedule by the amount of the deployment.

(c) ERCOT shall post a list of Load Resources that are not Controllable Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource Non-Spin award. The list will be broken into groups of approximately 500 MW increments. 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 groups of Load Resources that are not Controllable Load Resources providing Non-Spin as specified in the Other Binding Document titled "Non-Spinning Reserve Deployment and Recall Procedure."

(5) Subject to the exceptions described in paragraphs (a) and (b) below, On-Line Generation Resources that are assigned Non-Spin Ancillary Service Resource Responsibility during an Operating Hour shall always be deployed in that Operating Hour. This deployment shall be considered as a standing Protocol-directed Non-Spin deployment Dispatch Instruction. Within the 30-second window prior to the top-of-hour clock interval described in paragraph (2) of Section 6.3.2, Activities for Real-Time Operations, the QSE shall respond to the standing Non-Spin deployment Dispatch Instruction for those Generation Resources assigned Non-Spin Ancillary Service Resource Responsibility effective at the top-of-hour by adjusting the Non-Spin Ancillary Service Schedule telemetry. The QSE shall set the Non-Spin Ancillary Service Schedule telemetry equal to the portion of Non-Spin being provided from power augmentation if the portion being provided from power augmentation is participating as Off-Line Non-Spin, otherwise it shall be set to 0. As described in Section 6.5.7.2, Resource Limit Calculator, ERCOT shall adjust the HASL and LASL based on the QSE's telemetered Non-Spin Ancillary Service Schedule to account for such deployment and to make the energy from the full amount of the Non-Spin Ancillary Service Resource Responsibility available to SCED.

A Non-Spin deployment Dispatch Instruction from ERCOT is not required and these Generation Resources must be able to Dispatch their Non-Spin Ancillary Service Resource Responsibility in response to a SCED Base Point deployment instruction. The provisions of this paragraph (5) do not apply to:

(a) QSGRs assigned Off-Line Non-Spin Ancillary Service Resource Responsibility and provided to SCED for deployment, which must follow the provisions of Section 3.8.3, Quick Start Generation Resources; or

(b) The portion of On-Line Generation Resources that is only available through power augmentation if participating as Off-Line Non-Spin.

(6) Off-Line Generation Resources providing Non-Spin, while Off-Line and before the receipt of any deployment instruction, shall be capable of being dispatched to their Non-Spin Resource Responsibility within 30 minutes of a deployment instruction. Following a deployment instruction, the QSE shall reduce the Non-Spin Ancillary Service Schedule by the amount of the deployment. An Off-Line Generation Resource providing Non-Spin must also be brought On-Line with an Energy Offer Curve at an output level greater than or equal to P1 multiplied by LSL where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating Hour." These actions must be done within a time frame that would allow SCED to fully dispatch the Resource's Non-Spin Resource Responsibility within the 30 minute period using the Resource's Normal Ramp Rate curve. The Resource Status indicating that a Generation Resource has come On-Line with an Energy Offer Curve is ON as described in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria.

(7) For DSRs providing Non-Spin, on deployment of Non-Spin, the DSR's QSE shall adjust its Resource Output Schedule to reflect the amount of deployment. For non-DSRs with Output Schedules providing Non-Spin, on deployment of Non-Spin, ERCOT shall adjust the Resource Output Schedule for the remainder of the Operating Period to reflect the amount of deployment. ERCOT shall notify the QSEs representing the non-DSR of the adjustment through the MIS Certified Area.

(8) For On-Line Generation Resources providing Non-Spin, Base Points include Non-Spin energy as well as any other energy dispatched as a result of SCED. These Resources' Non-Spin Ancillary Service Resource Responsibility and Normal Ramp Rate curve should allow SCED to fully Dispatch the Resource's Non-Spin Resource Responsibility within the 30-minute time frame according to the Resources' Normal Ramp Rate curve. For the portion of the Non-Spin Ancillary Service Resource Responsibility provided from power augmentation participating as Off-Line, SCED should be able to be dispatch it within 30 minutes of the Non-Spin deployment instruction.

(9) Each QSE providing Non-Spin from a Resource shall inform ERCOT of the Non-Spin Resource availability using the Resource Status and Non-Spin Ancillary Service Resource Responsibility indications for the Operating Hour using telemetry and shall use the COP to inform ERCOT of Non-Spin Resource Status and Non-Spin Ancillary Service

Resource Responsibility for hours in the Adjustment Period through the end of the Operating Day.

(10) ERCOT may deploy Non-Spin at any time in a Settlement Interval.

(11) ERCOT's Non-Spin deployment Dispatch Instructions must include:

(a) The Resource name;

(b) A MW level of capacity deployment for Generation Resources with Energy Offer Curve, a MW level of energy for Generation Resources with Output Schedules, and a Dispatch Instruction for Load Resources equal to their awarded Non-Spin Ancillary Service Resource Responsibility; and

(c) The anticipated duration of deployment.

(12) ERCOT shall provide a signal via ICCP to the QSE of a deployed Generation or Load Resource indicating that its Non-Spin capacity has been deployed.

(13) ERCOT shall, as part of its TAC-approved Non-Spin deployment procedure, provide for the recall of Non-Spin energy including descriptions of changes to Output Schedules and release of energy obligations from On-Line Resources with Output Schedules and from On-Line Resources that were previously Off-Line Resources providing Non-Spin capacity.

(14) ERCOT shall provide a notification to all QSEs via the ERCOT website when any Non-Spin capacity is deployed on the ERCOT System showing the time, MW quantity and the anticipated duration of the deployment.

[NPRR863, NPRR1000, and NPRR1010: Replace applicable portions of Section 6.5.7.6.2.3 above with the following upon system implementation for NPRR863 or NPRR1000; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

(1) ERCOT shall deploy Non-Spin Service by operator Dispatch Instruction for the portion of On-Line Generation Resources that is only available through power augmentation and participating as Off-Line Non-Spin and Off-Line Generation Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spin Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed RRS, ECRS, or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that awarded on an individual Resource.

(2) Once Non-Spin capacity from Off-Line Generation Resources awarded Non-Spin is deployed and the Generation Resources are On-Line, ERCOT shall use SCED to determine the amount of energy to be dispatched from those Resources.

(3) Off-Line Generation Resources offering to provide Non-Spin must provide an Energy Offer Curve for use by SCED.

(4) Controllable Load Resources awarded Non-Spin shall have an RTM Energy Bid for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service award within 30 minutes, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource must comply with all requirements in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets."

(5) Off-Line Generation Resources awarded Non-Spin, while Off-Line and before the receipt of any deployment instruction, shall be capable of being dispatched to their Non-Spin award within 30 minutes of a Dispatch Instruction. On-Line Generation Resources awarded Non-Spin on the power augmentation capacity shall be capable of being dispatched to their Non-Spin award within 30 minutes of a Dispatch Instruction.

(6) ERCOT may deploy Non-Spin at any time in a Settlement Interval.

(7) ERCOT's Non-Spin deployment Dispatch Instructions must include:

(a) The Resource name;

(b) A MW level of capacity deployment for Generation Resources with Energy Offer Curve, a MW level of energy for Generation Resources with Output Schedules, and a Dispatch Instruction for Load Resources equal to their awarded Non-Spin Ancillary Service amount; and

(c) The anticipated duration of deployment.

(8) ERCOT shall provide a signal via ICCP to the QSE of a deployed Generation or Load Resource indicating that its Non-Spin capacity has been deployed.

(9) ERCOT shall, as part of its TAC-approved Non-Spin deployment procedure, provide for the recall of Non-Spin from On-Line Resources that were previously Off-Line Resources providing Non-Spin capacity and from On-Line Resources providing Non-Spin through power augmentation.

(10) ERCOT shall provide a notification to all QSEs via the ERCOT website when any Non-Spin capacity is deployed on the ERCOT System showing the time, MW quantity and the anticipated duration of the deployment.

ERCOT Impact Analysis Report

NPRR Number	1091	NPRR Title	Changes to Address Market Impacts of Additional Non-Spin Procurement
Impact Analysis Date	November 16, 2021		
Estimated Cost/Budgetary Impact	Between $120k and $160k		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 7 to 10 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 60% ERCOT; 40% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Market Operation Systems 73% • Data Management & Analytic Systems 20% • Energy Management Systems 7%		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	**1094**	**NPRR Title**	**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 Public Utility Commission of Texas (PUCT) approval - December 17, 2021		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	6.5.9.4.2, EEA Levels		
Related Documents Requiring Revision/Related Revision Requests	Nodal Operating Guide Revision Request (NOGRR) 233, Related to NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3 Nodal Operating Guide Section 4.5.3.3, EEA Levels		
Revision Description	This Nodal Protocol Revision Request (NPRR) allows 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 Nodal Operating Guide Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation under Nodal Operating Guide 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 Nodal Operating Guide 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 NPRR remove the prohibition from manually shedding any UFLS feeder-connected Load during an EEA Level 3. TOs and 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 NPRR in a timeline that would allow it to be considered at 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.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1094 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
PRS Decision	On 9/16/21, PRS voted unanimously via roll call to recommend approval of NPRR1094 as amended by the 9/15/21 Oncor comments. The Independent Retail Electric Provider (IREP) Market Segment did not participate in the vote. On 10/14/21, PRS voted unanimously via roll call to endorse and forward to TAC the 9/16/21 PRS Report and Impact Analysis for NPRR1094. All Market Segments participated in the vote.

Board Report

Summary of PRS Discussion	On 9/16/21, the sponsor provided an overview of the NPRR and 9/15/21 Oncor comments. On 10/14/21, there was no discussion.
TAC Decision	On 11/29/21, TAC voted unanimously via roll call to recommend approval of NPRR1094 as recommended by PRS in the 10/14/21 PRS Report with a recommended effective date of upon PUCT approval (12/17/21). 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 NPRR1094.
ERCOT Opinion	ERCOT supports approval of NPRR1094.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1094 and believes NPRR1094 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 NPRR1094 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	
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Comments Received	
Comment Author	**Comment Summary**

Oncor 091521	Reverted changes to paragraphs (2)(a)(i), (ii), and (vii) of Section 6.5.9.4.2 back to the original language; and modified paragraph (3)(b) of Section 6.5.9.4.2 to clarify the distinction between disconnecting a relay and shedding Load

Market Rules Notes

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

- NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
  - Section 6.5.9.4.2
- NPRR1106, Deployment of Emergency Response Service (ERS) Prior to Declaration of Energy Emergency Alert (EEA)
  - Section 6.5.9.4.2

Proposed Protocol Language Revision

6.5.9.4.2 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) At ERCOT's discretion, deploy available contracted ERS-30 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been deployed. The ERS-30 ramp period shall begin at the completion of the VDI.

(A) If less than 500 MW of ERS-30 is available for deployment, ERCOT shall deploy it as a single block.

(B) If the amount of ERS-30 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-30 as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS Resources in ERS-30 into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS Contract Period for ERS-30, ERCOT shall notify QSEs representing ERS Resources in ERS-30 of their ERS Resources' group assignments.

(C) ERS-30 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct their ERS Resources in 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-30 deployment or the ERS-30 Resources have reached their maximum deployment time.

(E) ERCOT shall notify QSEs of the release of ERS-30 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been recalled. The VDI shall represent the official notice of ERS-30 release. ERCOT may release ERS-30 as a block or by group designation.

(F) Upon release, an ERS Resource in ERS-30 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.

[NPRR1010: Insert paragraph (v) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(v) At ERCOT's discretion, manually deploy, through ICCP, available RRS and ECRS capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

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

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

(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.

[NPRR995 and NPRR1002: Insert applicable portions of paragraph (iii) below upon system implementation:]

(iii) Ensure that each of its ESRs and 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 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 DSPs or their agents to reduce Customer Load by using distribution voltage reduction measures, if deemed beneficial by the TSP, DSP, or their agents.

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

(iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30 and/or deploy RRS supplied from Load Resources (controlled by high-set under-frequency relays). ERCOT may deploy ERS-10, ERS-30, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

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

(iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30, and/or deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ERS-10, ERS-30, ECRS, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

(iv) ERCOT shall deploy ERS-10 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been deployed. The ERS-10 ramp period shall begin at the completion of the VDI.

(A) If less than 500 MW of ERS-10 is available for deployment, ERCOT shall deploy all ERS-10 Resources as a single block.

(B) If the amount of ERS-10 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-10 Resources as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS-10 Resources into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS-10 Contract Period, ERCOT shall notify QSEs representing ERS-10 Resources of their ERS-10 Resources' group assignments.

(C) ERS-10 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct ERS-10 Resources to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4 until ERCOT releases the ERS-10 deployment or the ERS-10 Resources have reached their maximum deployment times.

(E) ERCOT shall notify QSEs of the release of ERS-10 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been recalled. The VDI shall represent the official notice of ERS-10 release. ERCOT may release ERS-10 as a block or by group designation.

(F) Upon release, an ERS-10 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.

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

[NPRR863: Replace paragraph (v) above with the following upon system implementation:]

(v) 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;

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

(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;

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

(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

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

(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 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.

[NPRR939 and NPRR1010: Replace applicable portions of paragraph (D) above with the following upon system implementation for NPRR939; and upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(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.

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

(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 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 the 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.

ERCOT Impact Analysis Report

NPRR Number	<u>1094</u>	**NPRR Title**	**Allow Under Frequency Relay Load to be Manually Shed During EEA3**
Impact Analysis Date	September 28, 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	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	**<u>1101</u>**	**NPRR Title**	**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		
Timeline	Urgent – to allow ERCOT to consider the scope of this Nodal Protocol Revision Request (NPRR) as part of the project to implement NPRR1093, Load Resource Participation in Non-Spinning Reserve.		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2022; Rank – 3195		
Nodal Protocol Sections Requiring Revision	6.5.7.6.2.3, Non-Spinning Reserve Service Deployment		
Related Documents Requiring Revision/Related Revision Requests	Other Binding Document Revision Request (OBDRR) 035, 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		
Revision Description	This NPRR modifies the deployment 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. This deployment grouping process only addresses NCLR and Off-Line Generation Resources. Other Resources providing Non-Spin are not addressed in the proposed revisions.		
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)*		

Board Report

Business Case	This NPRR modifies the grouping requirements for NCLRs providing 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 NPRR and associated OBDRR035 will facilitate Non-Spin deployment for non-local issues in groups of roughly 500 MW which may include both NCLRs and Generation Resources. ERCOT is filing this NPRR and OBDRR035 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.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1101 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 grant NPRR1101 Urgent status. There was one abstention from the Independent Generator (Luminant) Market Segment. PRS then voted via roll call to recommend approval of NPRR1101 as submitted and to forward to TAC NPRR1101 and the Impact Analysis with a recommended priority of 2022 and rank of 3195. There was one abstention from the Consumer (Occidental Chemical) Market Segment. All Market Segments participated both votes.
Summary of PRS Discussion	On 11/10/21, ERCOT Staff provided an overview of NPRR1101 and the request for Urgent status.
TAC Decision	On 11/29/21, TAC unanimously voted via roll call to recommend approval of NPRR1101 as recommended by PRS in the 11/10/21 PRS Report as amended by the 11/19/21 ERCOT comments. 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 NPRR1101.
ERCOT Opinion	ERCOT supports approval of NPRR1101.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1101 and believes the market impact for NPRR1101 will improve ERCOT's ability to deploy Non-Spin in a technology agnostic manner, improve offer liquidity, and will allow ERCOT to procure the required quantities of Non-Spin more competitively.

Board Report

ERCOT Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1101 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	Cory Phillips
E-Mail Address	cory.phillips@ercot.com
Phone Number	512-248-6464

Comments Received	
Comment Author	**Comment Summary**
ERCOT 111921	Aligned the proposed revisions with baseline updates to Section 6.5.7.6.2.3 from the incorporation of NPRR1093 into the November 1, 2021 Protocols

Market Rules Notes

Please note that the following NPRR(s) also propose revisions to Section 6.5.7.6.2.3:

- NPRR1091, Changes to Address Market Impacts of Additional Non-Spin Procurement

Please note the baseline Protocol language in Section 6.5.7.6.2.3 has been updated to reflect the incorporation of the following NPRR(s) into the Protocols:

- NPRR1093 (incorporated 11/1/21)

Proposed Protocol Language Revision

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

(1) ERCOT shall deploy Non-Spin Service by operator Dispatch Instruction for the portion of On-Line Generation Resources that is only available through power augmentation and participating as Off-Line Non-Spin, Off-Line Generation Resources and Load Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spin Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed RRS or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that scheduled on an individual Resource.

(2) Once Non-Spin capacity from Off-Line Generation Resources providing Non-Spin is deployed and the Generation Resources are On-Line, ERCOT shall use SCED to determine the amount of energy to be dispatched from those Resources.

(3) Off-Line Generation Resources providing Non-Spin (OFFNS Resource Status) are required to provide an Energy Offer Curve for use by SCED.

(4) Non-Spin can be provided by Controllable Load Resources that are SCED qualified or by Load Resources that are not Controllable Load Resources but do not have an under-frequency relay or the under-frequency relay is not armed.

(a) A Controllable Load Resource providing Non-Spin shall have an RTM Energy Bid for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource must comply with all requirements in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets."

(b) A Load Resource that is not a Controllable Load Resource shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity. Following a deployment instruction, the QSE shall reduce the Non-Spin Ancillary Service Schedule by the amount of the deployment.

(5) ERCOT shall post a list of Off-Line Generation Resources and Load Resources that are not Controllable Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource Non-Spin award. The list will be broken into groups of approximately 500 MW increments. ERCOT shall develop a process for determining which individual Resource to place in each group based on a random sampling of individual Load Resources that are not Controllable Load Resources awarded Non-Spin and Generation Resources carrying Off-Line Non-Spin. At ERCOT's discretion, ERCOT may deploy one or all groups as specified in the Other Binding Document titled "Non-Spinning Reserve Deployment and Recall Procedure."

(a) On-Line Generation Resources participating in Off-Line Non-Spin using power augmentation will be randomly distributed in Real-Time among the groups created in the Day-Ahead for the purpose of manual deployment of Non-Spin by operator Dispatch Instruction.

(b) Any Generation Resource providing Off-Line Non-Spin that did not previously receive group assignment will be automatically considered in Group 1. Any Load Resource that is not a Controllable Load Resource providing Non-Spin in Real-Time that did not previously receive group assignment will be automatically considered in Group 1. ERCOT may assign a Generation Resource providing Off-Line Non-Spin or a Load Resource that is not a Controllable Load Resource to another group if that Resource did not previously receive group assignment and, in ERCOT's reasonable judgment, Group 1 is too large.

[NPRR1093: Replace paragraphs (4) and (5) above with the following upon system implementation:]

(4) Non-Spin can be provided by Controllable Load Resources that are SCED qualified or by Load Resources that are not Controllable Load Resources but do not have an under-frequency relay or the under-frequency relay is not armed.

(a) A Controllable Load Resource providing Non-Spin shall have an RTM Energy Bid for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource must comply with all requirements in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets."

(b) A Load Resource that is not a Controllable Load Resources shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity. Following a deployment instruction, the QSE shall reduce the Non-Spin Ancillary Service Schedule by the amount of the deployment.

(5) ERCOT shall post a list of Off-Line Generation Resources and Load Resources that are not Controllable Load Resources on the MIS Certified Area immediately following the DRUC for each QSE with a Load Resource Non-Spin award. The list will be broken into groups of approximately 500 MW increments. ERCOT shall develop a process for determining which individual Resource to place in each group based on a random sampling of individual Load Resources that are not Controllable Load Resources awarded Non-Spin and Generation Resources carrying Off-Line Non-Spin. At ERCOT's discretion, ERCOT may deploy all groups as specified in the Other Binding Document titled "Non-Spinning Reserve Deployment and Recall Procedure."

(a) On-Line Generation Resources participating in Off-Line Non-Spin using power augmentation will be randomly distributed in Real-Time among the groups created in the Day-Ahead for the purpose of manual deployment of Non-Spin by operator Dispatch Instruction.

(b) Any Generation Resource providing Off-Line Non-Spin that did not previously receive group assignment will be automatically considered in Group 1. Any Load Resource that is not a Controllable Load Resource providing Non-Spin in Real-Time that did not previously receive group assignment will be automatically considered in Group 1. ERCOT may assign a Generation Resource providing Off-Line Non-Spin or a Load Resource that is not a Controllable Load Resource to another group if that Resource did not previously receive group assignment and, in ERCOT's reasonable judgment, Group 1 is too large.

(6) Subject to the exceptions described in paragraphs (a) and (b) below, On-Line Generation Resources that are assigned Non-Spin Ancillary Service Resource Responsibility during an Operating Hour shall always be deployed in that Operating Hour. This deployment shall be considered as a standing Protocol-directed Non-Spin deployment Dispatch Instruction. Within the 30-second window prior to the top-of-hour clock interval described in paragraph (2) of Section 6.3.2, Activities for Real-Time Operations, the QSE shall respond to the standing Non-Spin deployment Dispatch Instruction for those Generation Resources assigned Non-Spin Ancillary Service Resource Responsibility effective at the top-of-hour by adjusting the Non-Spin Ancillary Service Schedule telemetry. The QSE shall set the Non-Spin Ancillary Service Schedule telemetry equal to the portion of Non-Spin being provided from power augmentation if the portion being provided from power augmentation is participating as Off-Line Non-Spin, otherwise it shall be set to 0. As described in Section 6.5.7.2, Resource Limit Calculator, ERCOT shall adjust the HASL and LASL based on the QSE's telemetered Non-Spin Ancillary Service Schedule to account for such deployment and to make the energy from the full amount of the Non-Spin Ancillary Service Resource Responsibility available to SCED. A Non-Spin deployment Dispatch Instruction from ERCOT is not required and these Generation Resources must be able to Dispatch their Non-Spin Ancillary Service Resource Responsibility in response to a SCED Base Point deployment instruction. The provisions of this paragraph (5) do not apply to:

(a) QSGRs assigned Off-Line Non-Spin Ancillary Service Resource Responsibility and provided to SCED for deployment, which must follow the provisions of Section 3.8.3, Quick Start Generation Resources; or

(b) The portion of On-Line Generation Resources that is only available through power augmentation if participating as Off-Line Non-Spin.

(7) Off-Line Generation Resources providing Non-Spin, while Off-Line and before the receipt of any deployment instruction, shall be capable of being dispatched to their Non-Spin Resource Responsibility within 30 minutes of a deployment instruction. Following a deployment instruction, the QSE shall reduce the Non-Spin Ancillary Service Schedule by the amount of the deployment. An Off-Line Generation Resource providing Non-Spin must also be brought On-Line with an Energy Offer Curve at an output level greater than

or equal to P1 multiplied by LSL where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating Hour." These actions must be done within a time frame that would allow SCED to fully dispatch the Resource's Non-Spin Resource Responsibility within the 30-minute period using the Resource's Normal Ramp Rate curve. The Resource Status indicating that a Generation Resource has come On-Line with an Energy Offer Curve is ON as described in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria.

(8) For DSRs providing Non-Spin, on deployment of Non-Spin, the DSR's QSE shall adjust its Resource Output Schedule to reflect the amount of deployment. For non-DSRs with Output Schedules providing Non-Spin, on deployment of Non-Spin, ERCOT shall adjust the Resource Output Schedule for the remainder of the Operating Period to reflect the amount of deployment. ERCOT shall notify the QSEs representing the non-DSR of the adjustment through the MIS Certified Area.

(9) For On-Line Generation Resources providing Non-Spin, Base Points include Non-Spin energy as well as any other energy dispatched as a result of SCED. These Resources' Non-Spin Ancillary Service Resource Responsibility and Normal Ramp Rate curve should allow SCED to fully Dispatch the Resource's Non-Spin Resource Responsibility within the 30-minute time frame according to the Resources' Normal Ramp Rate curve. For the portion of the Non-Spin Ancillary Service Resource Responsibility provided from power augmentation participating as Off-Line, SCED should be able to be dispatch it within 30 minutes of the Non-Spin deployment instruction.

(10) Each QSE providing Non-Spin from a Resource shall inform ERCOT of the Non-Spin Resource availability using the Resource Status and Non-Spin Ancillary Service Resource Responsibility indications for the Operating Hour using telemetry and shall use the COP to inform ERCOT of Non-Spin Resource Status and Non-Spin Ancillary Service Resource Responsibility for hours in the Adjustment Period through the end of the Operating Day.

(11) ERCOT may deploy Non-Spin at any time in a Settlement Interval.

(12) ERCOT's Non-Spin deployment Dispatch Instructions must include:

(a) The Resource name;

(b) A MW level of capacity deployment for Generation Resources with Energy Offer Curve, a MW level of energy for Generation Resources with Output Schedules, and a Dispatch Instruction for Load Resources equal to their awarded Non-Spin Ancillary Service Resource Responsibility; and

(c) The anticipated duration of deployment.

(13) ERCOT shall provide a signal via ICCP to the QSE of a deployed Generation or Load Resource indicating that its Non-Spin capacity has been deployed.

(14) ERCOT shall, as part of its TAC-approved Non-Spin deployment procedure, provide for the recall of Non-Spin energy including descriptions of changes to Output Schedules and release of energy obligations from On-Line Resources with Output Schedules and from On-Line Resources that were previously Off-Line Resources providing Non-Spin capacity.

(15) ERCOT shall provide a notification to all QSEs via the ERCOT website when any Non-Spin capacity is deployed on the ERCOT System showing the time, MW quantity and the anticipated duration of the deployment.

[NPRR863, NPRR1000, and NPRR1010: Replace applicable portions of Section 6.5.7.6.2.3 above with the following upon system implementation for NPRR863 or NPRR1000; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

(1) ERCOT shall deploy Non-Spin Service by operator Dispatch Instruction for the portion of On-Line Generation Resources that is only available through power augmentation and participating as Off-Line Non-Spin and Off-Line Generation Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spin Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed RRS, ECRS, or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that awarded on an individual Resource.

(2) Once Non-Spin capacity from Off-Line Generation Resources awarded Non-Spin is deployed and the Generation Resources are On-Line, ERCOT shall use SCED to determine the amount of energy to be dispatched from those Resources.

(3) Off-Line Generation Resources offering to provide Non-Spin must provide an Energy Offer Curve for use by SCED.

(4) Non-Spin can be provided by Controllable Load Resources that are SCED qualified or by Load Resources that are not Controllable Load Resources but do not have an under-frequency relay or the under-frequency relay is unarmed.

(a) Controllable Load Resources awarded Non-Spin shall have an RTM Energy Bid for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service award within 30 minutes, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource must comply with all requirements in the document titled "Requirements for Aggregate Load Resource Participation in the ERCOT Markets."

(b) A Load Resource that is not a Controllable Load Resource shall be capable of being Dispatched to its Non-Spin Ancillary Service Resource Responsibility within 30 minutes of a deployment instruction for capacity.

(5) Off-Line Generation Resources awarded Non-Spin, while Off-Line and before the receipt of any deployment instruction, shall be capable of being dispatched to their Non-Spin award within 30 minutes of a Dispatch Instruction. On-Line Generation Resources awarded Non-Spin on the power augmentation capacity shall be capable of being dispatched to their Non-Spin award within 30 minutes of a Dispatch Instruction.

(6) ERCOT may deploy Non-Spin at any time in a Settlement Interval.

(7) ERCOT shall develop a process to place Off-Line Generation Resources and Load Resources that are not Controllable Load Resources with Non-Spin award in a group based on a random sampling for the purpose of deploying these Resources manually. At ERCOT's discretion, ERCOT may deploy all groups as specified in the Other Binding Document titled "Non-Spinning Reserve Deployment and Recall Procedure."

(a) On-Line Generation Resources participating in Off-Line Non-Spin using power augmentation will be randomly distributed in Real-Time among the groups created in the Day-Ahead for the purpose of manual deployment of Non-Spin by operator Dispatch Instruction.

(b) Any Generation Resource providing Off-Line Non-Spin that did not previously receive group assignment will be automatically considered in Group 1. Any Load Resource that is not a Controllable Load Resource providing Non-Spin in Real-Time that did not previously receive group assignment will be automatically considered in Group 1. ERCOT may assign a Generation Resource providing Off-Line Non-Spin or a Load Resource that is not a Controllable Load Resource to another group if that Resource did not previously receive group assignment and, in ERCOT's reasonable judgment, Group 1 is too large.

(8) ERCOT's Non-Spin deployment Dispatch Instructions must include:

(a) The Resource name;

(b) A MW level of capacity deployment for Generation Resources with Energy Offer Curve, a MW level of energy for Generation Resources with Output Schedules, and a Dispatch Instruction for Load Resources equal to their awarded Non-Spin Ancillary Service amount; and

(c) The anticipated duration of deployment.

(9) ERCOT shall provide a signal via ICCP to the QSE of a deployed Generation or Load Resource indicating that its Non-Spin capacity has been deployed.

(10) ERCOT shall, as part of its TAC-approved Non-Spin deployment procedure, provide for the recall of Non-Spin from On-Line Resources that were previously Off-Line Resources providing Non-Spin capacity and from On-Line Resources providing Non-Spin through power augmentation.

(11) ERCOT shall provide a notification to all QSEs via the ERCOT website when any Non-Spin capacity is deployed on the ERCOT System showing the time, MW quantity and the anticipated duration of the deployment.

ERCOT Impact Analysis Report

NPRR Number	1101	NPRR Title	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		Between $30k and $50k See Comments	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 3 to 5 months See Comments	
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: • Data Management & Analytic Systems 60% • Market Operation Systems 40%	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		ERCOT will update grid operations and practices to implement this NPRR.	

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

Comments
The budgetary impact and estimated project duration assumes a coordinated delivery with NPR1093, Load Resource Participation in Non-Spinning Reserve.

Board Report

NPRR Number	1103	**NPRR Title**	**Securitization – PURA Subchapter M Default Charges**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to provide Protocol support for processes that will be used to assess and collect Default Charges to Qualified Scheduling Entities (QSEs) and Congestion Revenue Right (CRR) Account Holders pursuant to the Debt Obligation Order (DOO) issued in Public Utility Commission of Texas (PUCT) Docket No. 52321, Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M, of the Public Utility Regulatory Act (PURA)		
Proposed Effective Date	Phase 1 – Upon PUCT approval – December 17, 2021 Phase 2 – Upon system implementation (grey-boxed language)		
Priority and Rank Assigned	Priority – 2021; Rank – 320		
Nodal Protocol Sections Requiring Revision	2.1, Definitions 9.1.2, Settlement Calendar 16.11.4.7, Credit Monitoring and Management Reports 26, Securitization Default Charges (new) 26.1, Overview (new) 26.2, Securitization Default Charges (new) 26.3, Miscellaneous Invoices for Securitization Default Charges (new) 26.3, Securitization Default Charge Invoices (new) 26.3.1, Payment Process for Miscellaneous Invoices for Securitization Default Charges (new) 26.3.1.1, Invoice Recipient Payment to ERCOT for Miscellaneous Invoices for Securitization Default Charges (new) 26.3.1.2, Insufficient Payments by Miscellaneous Invoice Recipients for Securitization Default Charges (new) 26.3.1, Payment Process for Securitization Default Charge Invoices (new) 26.3.1.1, Invoice Recipient Payment to ERCOT for Securitization Default Charge Invoices (new) 26.3.1.2, Insufficient Payments by Invoice Recipients for Securitization Default Charge Invoices (new) 26.4, Securitization Default Charge Supporting Data Reporting (new) 26.4, Securitization Default Charge Supporting Data Reporting (new) 26.5, Securitization Default Charge Escrow Deposit Requirements (new)		

	26.5.1, Securitization Default Charge Escrow (new) 26.5.2, ERCOT Securitization Default Charge Credit Requirements for Counter-Parties (new) 26.5.3, Means of Satisfying Securitization Default Charge Credit Requirements (new) 26.5.4, Determination of Securitization Default Charge Credit Exposure for a Counter-Party (new) 26.5.5, Monitoring of a Counter-Party's Securitization Default Charge Credit Exposure by ERCOT (new) 26.5.6, Payment Breach and Late Payments by Market Participants (new) 26.5.7, Release of Market Participant's Securitization Default Charge Escrow Deposit Requirement (new)
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	This Nodal Protocol Revision Request (NPRR) establishes processes for the assessment and collection of Default Charges and Default Charge Escrow Deposits to QSEs and CRR Account Holders pursuant to the DOO issued in PUCT Docket No. 52321, Subchapter M, of PURA.
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	On October 13, 2021, the PUCT approved ERCOT's application for a DOO under PURA §39.603 and issued the DOO. The DOO requires ERCOT to assess Default Charges to and collect from QSEs and CRR Account Holders that represent the interests of obligated Market Participants on a pro rata basis in an amount sufficient to ensure the recovery of amounts necessary to timely provide payments of debt service and other required amounts and charges. The DOO further requires ERCOT to develop and adopt new Protocols governing the assessment and collection of Default Charges in accordance with the DOO and PURA.

Board Report

Credit Work Group Review	See 11/11/21 Credit WG comments
PRS Decision	On 11/10/21, PRS voted via roll call to grant NPRR1103 Urgent status. There was one abstention from the Independent Generator (Luminant) Market Segment. PRS then voted via roll call to recommend approval of NPRR1103 as amended by the 11/5/21 LCRA comments as revised by PRS and to forward to TAC NPRR1103 and the Impact Analysis with a recommended priority of 2021 and rank of 320. There was one abstention from the Municipal (CPS Energy) Market Segment. All Market Segments participated in both votes.
Summary of PRS Discussion	On 11/10/21, ERCOT Staff provided an overview of NPRR1103 and the request for Urgent status. Participants reviewed the 11/5/21 LCRA comments and proposed additional edits to maintain the second Business Day due date within Section 26.5.5.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NPRR1103 as recommended by PRS in the 11/10/21 PRS Report with a recommended effective date of upon PUCT approval (12/17/21) for Phase 1. There was one abstention from the Municipal (CPS Energy) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, TAC reviewed the Business Case, ERCOT Opinion, and ERCOT Market Impact Statement for NPRR1103; and discussed the budgetary impact to implement NPRR1103 would be supported by the securitization funding.
ERCOT Opinion	ERCOT supports approval of NPRR1103.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1103 and believes the market impact for NPRR1103 establishes processes for assessment and collection of Default Charges and Default Escrow Deposits to QSEs and CRR Account Holders as reflected in the DOO issued in PUCT Docket No. 52321, Subchapter M, of PURA.
ERCOT Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1103 as recommended by TAC in the 11/29/21 TAC Report and the Revised Impact Analysis.

Sponsor	
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Company	ERCOT

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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**
LCRA 110521	Proposed edits to extend from two Business Days to five Business Days due dates for Securitization Default Charge Invoices and for deposits following receipt of an ERCOT notice to increase escrow and to remove a reference to a "one-day, one-step" payment process
Credit WG 111121	Noted NPRR1103 will provide positive credit impacts which establish processes for assessment and collection of Default Charges and Default Escrow Deposits to QSEs and CRR Account Holders as reflected in the DOO issued in PUCT Docket No. 52321, Subchapter M, of PURA.

Market Rules Notes

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

Proposed Protocol Language Revision

2.1 DEFINITIONS

Securitization Default Balance

The amount financed by ERCOT pursuant to PURA Chapter 39, Subchapter M, as authorized by the Public Utility Commission of Texas (PUCT), but which may not exceed $800 million.

Securitization Default Charge

Charges assessed to Qualified Scheduling Entities (QSEs) and Congestion Revenue Right (CRR) Account Holders to repay the Securitization Default Balance.

9.1.2 Settlement Calendar

(1) ERCOT shall post and maintain on the ERCOT website a Settlement Calendar to denote, for each Operating Day, when:

(a) Each scheduled Settlement Statement for the DAM will be issued under Section 9.2.4, DAM Statement, and Section 9.2.5, DAM Resettlement Statement;

(b) Each scheduled Settlement Statement for the RTM will be issued under Section 9.5.4, RTM Initial Statement, Section 9.5.5, RTM Final Statement, Section 9.5.6, RTM Resettlement Statement, and Section 9.5.8, RTM True-Up Statement;

(c) Each Settlement Invoice will be issued under Section 9.6, Settlement Invoices for the Day-Ahead Market and Real-Time Market;

(d) Payments for the Settlement Invoice are due under Section 9.7, Payment Process for the Settlement Invoices;

(e) Each Default Uplift Invoice will be issued under Section 9.19, Partial Payments by Invoice Recipients;

(f) Payments for Default Uplift Invoices are due under Section 9.19.1, Default Uplift Invoices;

(g) Each Congestion Revenue Right (CRR) Auction Invoice will be issued under Section 9.8, CRR Auction Award Invoices;

(h) Payments for CRR Auction Invoices are due under Section 9.9, Payment Process for CRR Auction Invoices;

(i) Each CRR Auction Revenue Distribution (CARD) Invoice will be issued under Section 9.10, CRR Auction Revenue Distribution Invoices;

(j) Payments for CARD Invoices are due under Section 9.11, Payment Process for CRR Auction Revenue Distribution;

(k) Each CRR Balancing Account (CRRBA) Invoice will be issued under Section 9.12, CRR Balancing Account Invoices;

(l) Payments for CRRBA Invoices are due under Section 9.13, Payment Process for the CRR Balancing Account;

(m) Each miscellaneous Invoice for Securitization Default Charges will be issued under Section 26.3, Miscellaneous Invoices for Securitization Default Charges;

(n) Payments for miscellaneous Invoices for Securitization Default Charges are due under Section 26.3.1, Payment Process for Miscellaneous Invoices for Securitization Default Charges; and

[NPRR1103: Replace paragraphs (m) and (n) above with the following upon system implementation:]

(m) Securitization Default Charge Invoices will be issued in accordance with Section 26.3, Securitization Default Charge Invoices;

(n) Payments for Securitization Default Charge Invoices are due under Section 26.3.1, Payment Process for Securitization Default Charge Invoices; and

(o) Settlement and billing disputes for each scheduled Settlement Statement of an Operating Day and Settlement Invoice must be submitted under Section 9.14, Settlement and Billing Dispute Process.

(2) ERCOT shall notify Market Participants if any of the aforementioned data will not be available on the date specified in the Settlement Calendar.

16.11.4.7 Credit Monitoring and Management Reports

(1) ERCOT shall post twice each Business Day on the Market Information System (MIS) Certified Area each active Counter-Party's credit monitoring and management related reports as listed below. The first posting shall be made by 1200 and the second posting shall be made as close as reasonably possible to the close of the Business Day but no later than 2350. The reports listed in items (f) and (g) below are not required to be included in both first and second posting if the Counter-Party has no active CRR ownership. The reports listed in items (c), (d), (e), (f), and (g) below are not required to be included in the second post if there are no changes to the underlying data. ERCOT shall post one set of these reports on the MIS Certified Area on each non-Business Day for which an ACL is sent.

(a) Available Credit Limit (ACL) Summary Report;

(b) Total Potential Exposure (TPE) Summary Report;

(c) Minimum Current Exposure (MCE) Summary Report;

(d) Estimate Aggregate Liability (EAL) Summary Report;

(e) Estimated Aggregate Liability (EAL) Detail Report;

(f) Future Credit Exposure for CRR PTP Obligations (FCEOBL) Summary Report;

(g) Future Credit Exposure for CRR PTP Options (FCEOPT) Summary Report; and

[NPRR1103: Insert item (h) below upon system implementation:]

(h) Securitization Credit Exposure Report.

(2) The reports listed in paragraph (1) above will be posted to the MIS Certified Area in Portable Document File (PDF) format and Microsoft Excel (XLS) format. There shall be a provision to "open", "save" and "print" each report.

26 Securitization Default Charges

26.1 Overview

This section establishes processes for the assessment of Securitization Default Charges and Securitization Default Charge credit requirements.

26.2 Securitization Default Charges

(1) ERCOT shall issue Invoices to Qualified Scheduling Entities (QSEs) and Congestion Revenue Right (CRR) Account Holders to collect the monthly amount determined by ERCOT to be necessary to repay the Securitization Default Balance. ERCOT may assess Securitization Default Charges over a period of up to 30 years.

(2) Each Counter-Party's share of the Securitization Default Charge for a month is calculated using the best available Settlement data for the most recent month for which ERCOT has posted Final Settlement data for all Operating Days in the month (referred to below as "the reference month"), as follows:

$$\mathbf{SDCRSCP}_{\,\boldsymbol{cp}} = \mathbf{TSDCMA} * \mathbf{SDCMMARS}_{\,\boldsymbol{cp}}$$

Where:

$$\text{SDCMMARS}_{\,cp} = \text{SDCMMA}_{\,cp} / \text{SDCMMATOT}$$

$$\begin{aligned}\text{SDCMMA}_{\,cp} = \text{Max}\,\{\, & \textstyle\sum_{mp} (\text{SDCRTMG}_{\,mp} + \text{SDCRTDCIMP}_{\,mp}),\\ & \textstyle\sum_{mp} (\text{SDCRTAML}_{\,mp} + \text{SDCWSLTOT}_{\,mp}),\\ & \textstyle\sum_{mp} \text{SDCRTQQES}_{\,mp},\\ & \textstyle\sum_{mp} \text{SDCRTQQEP}_{\,mp},\\ & \textstyle\sum_{mp} \text{SDCDAES}_{\,mp},\\ & \textstyle\sum_{mp} \text{SDCDAEP}_{\,mp},\\ & \textstyle\sum_{mp} (\text{SDCRTOBL}_{\,mp} + \text{SDCRTOBLLO}_{\,mp}),\end{aligned}$$

$\sum_{mp}$ (SDCDAOPT $_{mp}$ + SDCDAOBL $_{mp}$ + SDCOPTS $_{mp}$ + SDCOBLS $_{mp}$),

$\sum_{mp}$ (SDCOPTP $_{mp}$ + SDCOBLP $_{mp}$)}

SDCMMATOT = $\sum_{cp}$ (SDCMMA $_{cp}$)

Where:

SDCRTMG $_{mp}$ = $\sum_{r, p, i}$ (RTMG $_{mp, r, p, i}$), excluding RTMG for Reliability Must-Run (RMR) Resources and RTMG in Reliability Unit Commitment (RUC)-Committed Intervals for RUC-committed Resources

SDCRTDCIMP $_{mp}$ = $\sum_{p, i}$ (RTDCIMP $_{mp, p, i}$) / 4

SDCRTAML $_{mp}$ = max(0,$\sum_{p, i}$ (RTAML $_{mp, p, i}$))

SDCRTQQES $_{mp}$ = $\sum_{p, i}$ (RTQQES $_{mp, p, i}$) / 4

SDCRTQQEP $_{mp}$ = $\sum_{p, i}$ (RTQQEP $_{mp, p, i}$) / 4

SDCDAES $_{mp}$ = $\sum_{p, h}$ (DAES $_{mp, p, h}$)

SDCDAEP $_{mp}$ = $\sum_{p, h}$ (DAEP $_{mp, p, h}$)

SDCRTOBL $_{mp}$ = $\sum_{(j, k), h}$ (RTOBL $_{mp, (j, k), h}$)

SDCRTOBLLO $_{mp}$ = $\sum_{(j, k), h}$ (RTOBLLO $_{mp, (j, k), h}$)

SDCDAOPT $_{mp}$ = $\sum_{(j, k), h}$ (OPT $_{mp, (j, k), h}$)

SDCDAOBL $_{mp}$ = $\sum_{(j, k), h}$ (DAOBL $_{mp, (j, k), h}$)

SDCOPTS $_{mp}$ = $\sum_{(j, k), h}$ (OPTS $_{mp, (j, k), h}$)

SDCOBLS $_{mp}$ = $\sum_{(j, k), h}$ (OBLS $_{mp, (j, k), h}$)

SDCOPTP $_{mp}$ = $\sum_{(j, k), h}$ (OPTP $_{mp, j, h}$)

SDCOBLP $_{mp}$ = $\sum_{(j, k), h}$ (OBLP $_{mp, (j, k), h}$)

SDCWSLTOT $_{mp}$ = (-1) * $\sum_{r, b}$ (MEBL $_{mp, r, b}$)

The above variables are defined as follows:

Variable	Unit	Definition
SDCRSCP $_{cp}$	$	*Securitization Default Charge Ratio Share per Counter-Party*—The Counter-Party's pro rata portion of the total Securitization Charges for a month.

Variable	Unit	Definition
TSDCMA	$	*Total Securitization Default Charge Monthly Amount*—The amount ERCOT determines must be collected for the month in order to timely repay the Securitization Default Balance.
SDCMMARS $_{cp}$	None	*Securitization Default Charge Maximum MWh Activity Ratio Share*—The Counter-Party's pro rata share of Maximum MWh Activity.
SDCMMA $_{cp}$	MWh	*Securitization Default Charge Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction for the reference month.
SDCMMATOT	MWh	*Securitization Default Charge Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity.
RTMG $_{mp, p, r, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTMG $_{mp}$	MWh	*Securitization Default Charge Real-Time Metered Generation per Market Participant*—The monthly sum in the reference month of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTDCIMP $_{mp, p, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTDCIMP $_{mp}$	MW	*Securitization Default Charge Real-Time DC Import per Market Participant*—The monthly sum in the reference month of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.
RTAML $_{mp, p, i}$	MWh	*Real-Time Adjusted Metered Load per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML) at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTAML $_{mp}$	MWh	*Securitization Default Charge Real-Time Adjusted Metered Load per Market Participant*—The monthly sum in the reference month of the AML represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQES $_{mp, p, i}$	MW	*QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTQQES $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Sale per Market Participant*—The monthly sum in the reference month of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.

Variable	Unit	Definition
SDCRTQQEP $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum in the reference month of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAES $_{mp, p, h}$	MW	*Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE.
SDCDAES $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Sale per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAEP $_{mp, p, h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared DAM Energy Bids at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.
SDCDAEP $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Purchase per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared DAM Energy Bids, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBL $_{mp, (j, k), h}$	MW	*Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE.
SDCRTOBL $_{mp}$	MWh	*Securitization Default Charge Real-Time Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBLLO $_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
SDCRTOBLLO $_{q, (j, k)}$	MW	*Securitization Default Charge Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total in the reference month of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.
OPT $_{mp, (j, k), h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
SDCDAOPT $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Option per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.

Variable	Unit	Definition
DAOBL $_{mp,\ (j,\ k),\ h}$	MW	*Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
SDCDAOBL $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTS $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTS $_{mp}$	MWh	*Securitization Default Charge PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLS $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTP $_{mp}$	MWh	*Securitization Default Charge PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLP $_{mp,\ (j,\ k),\ a,\ h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLP $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
SDCWSLTOT $_{mp}$	MWh	*Securitization Default Charge Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum in the reference month of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.

Variable	Unit	Definition
MEBL $_{mp, r, b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*.
cp	none	A registered Counter-Party.
mp	none	A Market Participant that is a QSE or CRR Account Holder with activity in the reference month, except for a Market Participant exempt from Securitization Default Charges pursuant to the Final Order entered by the Public Utility Commission of Texas (PUC) in PUC Docket No. 52321. Defaulted Market Participants with market activity in the reference month are included in the calculation.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval i.
r	none	A Resource.

(3) The Securitization Default Charge amount will be allocated to the QSE or CRR Account Holder assigned to a registered Counter-Party based on the pro-rata share of MWhs that the QSE or CRR Account Holder contributed to its Counter-Party's maximum MWh activity ratio share.

(4) As needed, but no less than annually, ERCOT will conduct an evaluation to determine if the Total Securitization Default Charge Monthly Amount (TSDCMA), which is the amount collected each month to repay the Securitization Default Balance, should be modified. In conducting this evaluation, ERCOT will calculate the amount that must be collected each month to service the then-remaining Securitization Default Balance debt in even monthly amounts over the remaining tenor of the debt.

(5) If ERCOT modifies the TSDCMA pursuant to paragraph (4) above, ERCOT will issue a Market Notice notifying Market Participants of the change no later than 15 days before the beginning of the month in which the new TSDCMA will be used to calculate the Securitization Default Charges.

26.3 Miscellaneous Invoices for Securitization Default Charges

(1) ERCOT shall prepare miscellaneous Invoices for Securitization Default Charges on a monthly basis, as specified in Section 9.1.2, Settlement Calendar, on the seventh Business Day of a month. Unless expressly stated otherwise, the publication of the miscellaneous Invoices can occur as late as 2400 on the scheduled publication date. The Market Participant to whom the Invoice is addressed ("Invoice Recipient") is a payor.

(2) Each Invoice Recipient shall pay any debit shown on the miscellaneous Invoice for Securitization Default Charges on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit.

(3) ERCOT shall post miscellaneous Invoices for Securitization Default Charges on the Market Information System (MIS) Certified Area. The Invoice Recipient is responsible for accessing the Invoices on the MIS Certified Area once posted by ERCOT, as described in Section 9.1.3, Settlement Statement and Invoice Access.

(4) All disputes for miscellaneous Invoices related to the Securitization Default Charges shall follow the process described in Section 9.14, Settlement and Billing Dispute Process.

26.3.1 Payment Process for Miscellaneous Invoices for Securitization Default Charges

(1) Payments for miscellaneous Invoices for Securitization Default Charges are due on a Business Day and Bank Business Day basis in a process detailed below.

26.3.1.1 Invoice Recipient Payment to ERCOT for Miscellaneous Invoices for Securitization Default Charges

(1) The payment due date and time for the miscellaneous Invoices for Securitization Default Charges, with funds owed by an Invoice Recipient, is 1700 on the fifth Bank Business Day after the miscellaneous Invoice date, unless the fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All miscellaneous Invoices for Securitization Default Charges due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars (USDs) by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date. EFTs must be with U.S. banks only.

(3) Miscellaneous Invoices that are issued for Securitization Default Charges are distinct from other Invoices issued by ERCOT and must be paid by an EFT that is separate from any other Invoice. An Invoice Recipient may not net amounts owing on a miscellaneous Invoice for Securitization Default Charges with any other funds due to or from ERCOT.

(4) Payments for Securitization Default Charges must be made to the account listed on the invoice. If payment is not made to the correct account, the payment will be rejected. Failure to remit funds to the correct account may result in a Payment Breach. The payment remark must include the invoice number.

26.3.1.2 Insufficient Payments by Miscellaneous Invoice Recipients for Securitization Default Charges

(1) If an Invoice Recipient owing funds does not pay its miscellaneous Invoice for Securitization Default Charges in full (short-pay) by the payment due date and time set forth in Section 26.3.1.1, Invoice Recipient Payment to ERCOT for Miscellaneous Invoices for Securitization Default Charges, ERCOT shall follow the procedure set forth below:

(a) ERCOT shall draw on any available Securitization Default Charge escrow deposit by the short-paying miscellaneous Invoice Recipient.

(b) Regardless of whether ERCOT's draw on an available Securitization Default Charge escrow deposit under paragraph (a) above is sufficient to cover the amount owed by a Market Participant for a miscellaneous Invoice for Securitization Default Charges, a Market Participant's failure to pay the miscellaneous Invoice by the payment due date and time will still be deemed a Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(c) If an amount owed to ERCOT for a miscellaneous Invoice for Securitization Default Charges cannot be fully recovered from a short-paying Market Participant by drawing upon available Securitization Default Charge escrow deposits or taking other action against the Market Participant to recover the amount owed, the remaining short payment amount will be taken into consideration in ERCOT's next evaluation of the Total Securitization Default Charge Monthly Amount performed pursuant to paragraph (4) of Section 26.2, Securitization Default Charges, that occurs after the short payment.

(d) Any action taken by ERCOT under this section does not relieve or otherwise excuse the short paying Market Participant of its obligation to fully pay all outstanding financial obligations to ERCOT, including is obligation to fully pay all miscellaneous Invoices for Securitization Default Charges.

[NPRR1103: Sections 26.3, 26.3.1, 26.3.1.1, and 26.3.1.2 above with the following upon system implementation:]

26.3 Securitization Default Charge Invoices

(1) ERCOT shall prepare Securitization Default Charge Invoices on a monthly basis, as specified in Section 9.1.2, Settlement Calendar, on the seventh Business Day of a month. Unless expressly stated otherwise, the publication of the Securitization Default Charge Invoices can occur as late as 2400 on the scheduled publication date. The Market Participant to whom the Invoice is addressed ("Invoice Recipient") is a payor.

(2) Each Invoice Recipient shall pay any debit shown on the Securitization Default Charge Invoice on the payment due date, whether or not there is any Settlement and billing dispute regarding the amount of the debit.

(3) ERCOT shall post the Securitization Default Charge Invoice on the MIS Certified Area. The Invoice Recipient is responsible for accessing the Securitization Default Charge Invoice on the MIS Certified Area once posted by ERCOT, as described in Section 9.1.3, Settlement Statement and Invoice Access.

(4) The Securitization Default Charge Invoice must comply with the Settlement payment convention, as set forth in Section 9.1.5, Settlement Payment Convention.

(5) Securitization Default Charge Invoices must contain the following information:

(a) The Invoice Recipient's name;

(b) The ERCOT identifier (Settlement identification number issued by ERCOT);

(c) Net Amount Owed– the charge owed by an Invoice Recipient;

(d) Time Period – the reference month for which the Securitization Default Charge Invoice is generated;

(e) Run Date – the date on which the Invoice was created and published;

(f) Invoice Reference Number – a unique number generated by ERCOT for payment tracking purposes;

(g) Payment Date and Time – the date and time the Invoice amounts must be paid;

(h) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT Securitization Default Charge account to which any amounts owed by the Invoice Recipient are to be paid; and

(i) Overdue Terms – the terms that would apply if the payments were received late.

(6) All disputes for Securitization Default Charge Invoices shall follow the process described in Section 9.14, Settlement and Billing Dispute Process.

26.3.1 Payment Process for Securitization Default Charge Invoices

(1) Payments for Securitization Default Charge Invoices are due on a Business Day and Bank Business Day basis in a process detailed below.

26.3.1.1 Invoice Recipient Payment to ERCOT for Securitization Default Charge Invoices

(1) The payment due date and time for Securitization Default Charge Invoices, with funds owed by an Invoice Recipient, is 1700 on the fifth Bank Business Day after the Securitization Default Charge Invoice date, unless fifth Bank Business Day is not a Business Day. If the fifth Bank Business Day is not a Business Day, then the payment is due by 1700 on the next Bank Business Day after the fifth Bank Business Day that is also a Business Day.

(2) All Securitization Default Charge Invoices due, with funds owed by an Invoice Recipient, must be paid to ERCOT in U.S. Dollars (USDs) by Electronic Funds Transfer (EFT) in immediately available or good funds (i.e., not subject to reversal) on or before the payment due date. EFTs must be with U.S. banks only.

(3) Securitization Default Charge Invoices are distinct from other Invoices issued by ERCOT and must be paid by an EFT that is separate from any other Invoice. An Invoice Recipient may not net amounts owing on a Securitization Default Charge Invoice with any other funds due to or from ERCOT.

(4) Payments for Securitization Default Charges must be made to the account listed on the Invoice. If payment is not made to the correct account, the payment will be rejected. Failure to remit funds to the correct account may result in a Payment Breach. The payment remark must include the Invoice number.

26.3.1.2 Insufficient Payments by Invoice Recipients for Securitization Default Charge Invoices

(1) If an Invoice Recipient owing funds does not pay its Securitization Default Charge Invoice in full (short-pay) by the payment due date and time set forth in Section 26.3.1.1, ERCOT shall follow the procedure set forth below:

(a) ERCOT shall draw on any available Securitization Default Charge escrow deposits by the Invoice Recipient.

(b) Regardless of whether ERCOT's draw on available Securitization Default Charge escrow deposits under paragraph (a) above is sufficient to cover the amount owed by a Market Participant for a Securitization Default Charge Invoice, a Market Participant's failure to pay the Invoice by the payment due date and time will still be deemed a Payment Breach under Section 16.11.6, Payment Breach and Late Payments by Market Participants.

(e) If an amount owed to ERCOT for a Securitization Default Charge Invoice cannot be fully recovered from a short-paying Market Participant by drawing upon available Securitization Default Charge escrow deposits or taking other action against the Market Participant to recover the amount owed, the remaining short payment amount will be taken into consideration in ERCOT's next evaluation of the Total Securitization Default Charge Monthly Amount performed pursuant to paragraph (4) of Section 26.2, Securitization Default Charges, that occurs after the short payment.

(f) Any action taken by under this section does not relieve or otherwise excuse the short paying Market Participant of its obligation to fully pay all outstanding financial obligations to ERCOT, including is obligation to fully pay all Securitization Default Charge Invoices.

26.4 Securitization Default Charge Supporting Data Reporting

(1) On a monthly basis, ERCOT shall post the following information on the Market Information System (MIS) Certified Area:

(a) Securitization Default Charge Maximum MWh Activity (SDCMMA);

(b) Securitization Default Charge Maximum MWh Activity Total (SDCMMATOT);

(c) Securitization Default Charge Maximum MWh Activity Ratio Share (SDCMMARS); and

(d) Counter-Party level components of the SDCMMA calculation, as defined in paragraph (2) of Section 26.2, Securitization Default Charges.

(2) ERCOT shall post separate reports containing Initial and Final Settlement data as such data becomes available.

[NPRR1103: Section 26.4 above with the following upon system implementation:]

26.4 Securitization Default Charge Supporting Data Reporting

(1) On a monthly basis, ERCOT shall post the following information on the Market Information System (MIS) Certified Area:

(a) Securitization Default Charge Maximum MWh Activity (SDCMMA);

(b) Securitization Default Charge Maximum MWh Activity Total (SDCMMATOT);

(c) Securitization Default Charge Maximum MWh Activity Ratio Share (SDCMMARS): and

(d) Counter-Party level components of the SDCMMA calculation, as defined in paragraph (2) of Section 26.2, Securitization Default Charge.

(2) ERCOT shall post a report containing Initial Settlement data as such data becomes available. The report shall be updated with Final Settlement data as such data becomes available.

26.5 Securitization Default Charge Escrow Deposit Requirements

26.5.1 Securitization Default Charge Escrow

(1) The term "Securitization Default Charge escrow deposit" means the amount required to be deposited with ERCOT in the form of cash or an unconditional, irrevocable letter of credit to be held in escrow for a Market Participant's obligation to pay Securitization Default Charges.

(2) Although ERCOT is the servicer for the assessment and collection of Securitization Default Charges, by providing escrow deposits pursuant to this Section each Counter-Party grants the Texas Electric Market Stabilization Funding M LLC (TEMSFM) a secured interest in Securitization Default Charge escrow deposits to secure its obligation to pay the same.

(3) The security interest of TEMSFM is perfected upon a Counter-Party's deposit of cash or a letter of credit with ERCOT pursuant to this Section.

26.5.2 ERCOT Securitization Default Charge Credit Requirements for Counter-Parties

(1) A Counter-Party must, at all times, maintain its Securitization Default Charge escrow deposit at or above the amount of its Securitization Default Charge Credit Exposure (SDCCE). Each Counter-Party shall maintain any required Securitization Default Charge escrow deposit in a form acceptable to ERCOT in its sole discretion pursuant to Section 26.5.3, Means of Satisfying Securitization Default Charge Credit Requirements.

(2) If at any time a Counter-Party does not meet ERCOT's SDCCE requirements, then the Counter-Party will be considered to be in Payment Breach and ERCOT may suspend the Counter-Party's rights under these Protocols until it meets the SDCCE requirements.

(3) ERCOT's failure to suspend a Counter-Party's rights on any particular occasion does not prevent ERCOT from suspending those rights on any subsequent occasion, including a CRR Account Holder's ability to bid on future CRRs or a Qualified Scheduling Entity's ability to bid in the Day-Ahead Market (DAM).

26.5.3 Means of Satisfying Securitization Default Charge Credit Requirements

(1) If a Counter-Party is required to provide a Securitization Default Charge escrow deposit, then it may do so through one or both of the following means:

(a) The Counter-Party may give an unconditional, irrevocable letter of credit naming Texas Electric Market Stabilization Funding M LLC (TEMSFM) as the beneficiary. ERCOT or the TEMSFM may reject the letter of credit if the issuer is unacceptable to ERCOT or TEMSFM or if the conditions under which ERCOT or TEMSFM may draw against the letter of credit are unacceptable to ERCOT or TEMSFM.

(b) All letters of credit must be drawn on a US domestic bank or a domestic office of a foreign bank, and must meet the requirements in Section 16.11.3, Alternative Means of Satisfying ERCOT Creditworthiness Requirement.

(c) Letters of credit held as Securitization Default Charge escrow deposits are subject to letter of credit issuer limits as specified in paragraph (1) of Section 16.11.3.

(d) The Counter-Party may deposit cash with ERCOT with the understanding that ERCOT may draw part or all of the deposited cash to satisfy any overdue payments owed by the Counter-Party to ERCOT for Securitization Default Charges. The cash deposits may bear interest payable directly to the Counter-Party, but any such arrangements may not restrict ERCOT's immediate access to the cash.

(i) Interest on cash deposited pursuant to this Section will be calculated based on Counter-Party average cash deposit balance. Interest is not paid on a cash deposit balance held by ERCOT where, in accordance with paragraph (4) of Section 16.11.7, Release of Market Participant's Financial Security Requirement, the Counter-Party's Standard Form Market Participant Agreement has been terminated and ERCOT has determined that no obligations for Securitization Default Charges remain owing or will become due and payable.

(ii) Once per year, ERCOT will return interest earned on a Counter-Party's cash deposits pursuant to this Section to the Counter-Party.

(2) Securitization Default Charge escrow deposits are held solely for the purpose of collateralizing Securitization Default Charge credit exposure. They are independent of and in addition to any other Financial Security obligations of the Counter-Party arising under Section 16.11, Financial Security for Counter-Parties.

(3) A Counter-Party with excess cash held with respect to one or more Securitization Default Charge escrow deposit requirements may request ERCOT to return some or all of the excess cash to the Counter-Party.

(4) Securitization Default Charge escrow deposits will not be used to pay periodic Securitization Default Charge Invoices unless there is an insufficient payment by the Invoice Recipient, in accordance with Section 26.3.1.2, Insufficient Payments by Miscellaneous Invoice Recipients for Securitization Default Charges.

(5) Securitization Default Charge escrow deposits in excess of the Securitization Default Charge Credit Exposure requirement shall not be used to cover insufficient payments of Settlement Invoices for ERCOT market activities under Section 9.19, Partial Payments by Invoice Recipients, or requests for additional Financial Security made in accordance with paragraph (6) of Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT.

26.5.4 *Determination of Securitization Default Charge Credit Exposure for a Counter-Party*

(1) For each Counter-Party, ERCOT shall calculate the Securitization Default Charge credit exposure as follows:

$$\text{SDCCE}_{cp} = \text{SDCMMARS}_{cp,\,rm,\,s} * \sum_{fmd=1}^{nfmd} (\text{TSDCMA}_{fmd})$$

The above variables are defined as follows:

Variable	Unit	Description
SDCCE_{cp}	$	*Securitization Default Charge Credit Exposure* – Estimated credit exposure for each Counter-Party related to Securitization Default Charges.
$\text{SDCMMARS}_{cp,\,om,\,s}$	None	*Securitization Default Charge Maximum MWh Activity Ratio Share* – The Counter-Party's pro rata share of Securitization Default Charge

Variable	Unit	Description
		Maximum MWh Activity in the most recent available reference month *rm* based on Initial Settlements.
TSDCMA	$	*Total Securitization Default Charge Monthly Amount* – The amount ERCOT determines must be collected for the month in order to timely repay the Securitization Default Balance.
cp	none	A registered Counter-Party.
rm	none	*Reference Month* – most recent available operating month
fmd	None	*Forward Month* – a month from Securitization Default Charge forward months
nfmd	None	*Number of forward months* – total number of forward months Securitization Default Charge is extrapolated

The above parameters are defined as follows:

Parameter	Unit	Current Value
nfmd	Months	4

26.5.5 Monitoring of a Counter-Party's Securitization Default Charge Credit Exposure by ERCOT

(1) Pursuant to Section 16.11.5, Monitoring of a Counter-Party's Creditworthiness and Credit Exposure by ERCOT, ERCOT shall monitor the credit exposure of each Counter-Party, including Securitization Default Charge credit exposure.

(2) A Counter-Party is responsible at all times for maintaining Securitization Default Charge escrow deposits in an amount equal to or greater than that Counter-Party's Securitization Default Charge credit exposure.

(3) ERCOT shall promptly notify each Counter-Party of the need to increase its Securitization Default Charge escrow deposit and allow the Counter-Party time, as provided in paragraph (5) below, to provide additional Securitization Default Charge escrow deposits to maintain compliance with this Section.

(4) ERCOT may suspend a Counter-Party when that Counter-Party's SDCCE, as defined in Section 26.5.4, exceeds 100% of its Securitization Default Charge escrow deposit. Any failure by ERCOT to send a Notice as set forth in this Section does not relieve the Counter-Party from the obligation to maintain appropriate Securitization Default Charge escrow deposits in amounts equal to or greater than that Counter-Party's SDCCE.

(5) To the extent that a Counter-Party fails to maintain Securitization Default Charge escrow deposit in amounts equal to or greater than its SDCCE, each as defined in Section 26.5.4:

(a) ERCOT shall promptly notify the Counter-Party of the amount by which its Securitization Default Charge escrow deposit must be increased and allow it:

(i) Until 1500 on the second Bank Business Day from the date on which ERCOT delivered the notice to increase its Securitization Default Charge escrow deposit if ERCOT delivered its Notice before 1500; or

(ii) Until 1700 on the second Bank Business Day from the date on which ERCOT delivered notification to increase its Securitization Default Charge escrow deposit if ERCOT delivered its notice after 1500 but prior to 1700.

(b) ERCOT shall notify the QSE's Authorized Representative(s) and Credit Contact if it has not received the required security by 1530 on the Bank Business Day on which the security was due; however, failure to notify the Counter-Party's representatives or credit contacts that the required security was not received does not prevent ERCOT from exercising any of its other rights under this Section.

(c) ERCOT is not required to make any payment to a Counter-Party unless and until the Counter-Party increases its Securitization Default Charge escrow deposit to an amount equal to or greater than that Counter-Party's SDCCE. The payments that ERCOT may not make to a Counter-Party include Invoice receipts, CRR revenues, CRR credits, reimbursements for short payments, and any other reimbursements or credits under any other agreement between the Market Participant and ERCOT. ERCOT may retain all such amounts until the Counter-Party has fully discharged all payment obligations owed to ERCOT under the Agreement, other agreements, and these Protocols.

(6) If a Counter-Party increases its Securitization Default Charge escrow deposit as required by ERCOT by the deadline in paragraph (5)(a) above, then ERCOT shall release any payments held, providing the Counter-Party has no other payment deficiencies with respect to any other activity under these Protocols.

26.5.6 Payment Breach and Late Payments by Market Participants

(1) In the event of a Payment Breach or Late Payment by a Market Participant with respect to Securitization Default Charge Invoices or required Securitization Default Charge escrow deposits, all remedies specified in Section 16.11.6, Payment Breach and Late Payments by Market Participants, are applicable.

26.5.7 Release of Market Participant's Securitization Default Charge Escrow Deposit Requirement

(1) Following the termination of a Market Participant's Standard Form Market Participant Agreement, ERCOT shall retain all Securitization Default Charge escrow deposits to cover, if necessary, potential future obligations for Securitization Default Charges.

(2) Upon ERCOT's sole determination that all potential Securitization Default Charge Invoices have been paid, ERCOT shall return or release any remaining Securitization Default Charge escrow deposits to the terminated Market Participant.

Revised ERCOT Impact Analysis Report

NPRR Number	1103	NPRR Title	Securitization – PURA Subchapter M Default Charges
Impact Analysis Date	December 1, 2021		
Estimated Cost/Budgetary Impact	Between $1.5M and $2M This NPRR relates to implementation activities associated with Texas House Bill 4492 (Public Utility Regulatory Act (PURA) Subchapter M) and the related Public Utility Commission of Texas (PUCT) Debt Obligation Order for a debt financing mechanism to securitize costs from Winter Storm Uri. As such, the Estimated Cost/Budgetary Impact for this NPRR will not be funded from the ERCOT budget (i.e., ERCOT System Administration Fee) (see Comments section for details). See ERCOT Staffing Impacts		
Estimated Time Requirements	Phase 1: Manual No project required. This Nodal Protocol Revision Request (NPRR) can be implemented using manual business processes and can take effect upon PUCT approval. Phase 2: Automation The timeline for automating this NPRR is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 18 to 26 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 100% ERCOT; 0% Vendor There will be ongoing operational impacts to the following ERCOT departments to support this NPRR: * Settlement Services * Commercial Application Services As previously stated in the Estimated Cost/Budgetary Impact section, since this NPRR relates to implementation activities of Texas House Bill 4492 and the related PUCT Debt Obligation Order, any long-term ERCOT staffing impacts will not be funded from the ERCOT budget (see Comments section for details).		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Credit Management Systems (CMM) 74% • Credit, Settlements & Billing Systems 20% • Data Management & Analytic Systems 2%		

	• Integration Systems 1% • Financial Management Systems 1% • ERCOT Website and MIS Systems 1% • CRM & Registration Systems 1%
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
In accordance with Texas House Bill 4492, project and costs related to the securitization activities will be funded as part of the services costs in support of the financing. Subchapter M Sec. 39.602 (1)(C) reasonable costs incurred by a state agency or the independent organization to implement a debt obligation order under Sections 39.603 and 39.604 Further in the PUCT Debt Obligation Order, Ordering Paragraph 18 states the following: 18. Ongoing Costs. The Commission authorizes ERCOT to recover its actual ongoing costs through its default charges in accordance with the terms of this Order.

Board Report

NPRR Number	<u>**1104**</u>	**NPRR Title**	**As-Built Definition of Real Time Liability Extrapolated (RTLE)**
Date of Decision	December 10, 2021		
Action	Recommended Approval		
Timeline	Urgent – to correctly align Protocols with ERCOT's credit systems as soon as possible.		
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	16.11.4.3, Determination of Counter-Party Estimated Aggregate Liability		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) corrects the definition of Real Time Liability Extrapolated (RTLE) to include market activity for Entities that have no Load or generation but have Real-Time exposure. It has come to ERCOT's attention that the current definition of RTLE is erroneously tied to Qualified Scheduling Entities (QSEs) that represent Load or generation, and conflicts with the implementation of RTLE in ERCOT's credit system.		
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	In the development and approval of NPRR620, Collateral Requirements for Counter-Parties with No Load or Generation, and NPRR741, Clarifications to TPE and EAL Credit Exposure Calculations, the RTLE definition for traders was incorrectly modified		

	to include the phrase "for a QSE that represents either Load or generation". NPRR620 had a separate RTLE definition for a QSE, trader, and Congestion Revenue Right (CRR) Account Holder. However, while NPRR620 was in grey-box, NPRR741 was approved, rolling back several of the grey-boxed items from NPRR620, and this phrase should have been removed from the RTLE definition as part of NPRR741. It was retained in error, so when NPRR620 and NPRR741 were implemented in the June 2, 2019 Nodal Protocols, the definition of RTLE in Section 16.11.4.3 incorrectly excludes market activity for Entities who have no Load or generation but have Real-Time exposure.
Credit Work Group Review	See 11/11/21 Credit WG comments
PRS Decision	On 11/10/21, PRS voted via roll call to grant NPRR1104 Urgent status. There was one abstention from the Independent Generator (Luminant) Market Segment. PRS then voted via roll call to recommend approval of NPRR1104 as submitted and to forward to TAC NPRR1104 and the Impact Analysis. There was one abstention from the Consumer (Occidental Chemical) Market Segment. All Market Segments participated both votes.
Summary of PRS Discussion	On 11/10/21, ERCOT Staff provided an overview of NPRR1104 and the request for Urgent status.
TAC Decision	On 11/29/21, TAC unanimously voted via roll call to recommend approval of NPRR1104 as recommended by PRS in the 11/10/21 PRS Report with a recommended effective date of upon PUCT approval (12/17/21). 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 NPRR1104.
ERCOT Opinion	ERCOT supports approval of NPRR1104.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1104 and believes the market impact for NPRR1104 brings Protocols in line with current credit systems and more appropriately reflects the forward risk related to the RTLE calculation.
ERCOT Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1104 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Vanessa Spells

Board Report

E-mail Address	Vanessa.spells@ercot.com
Company	ERCOT
Phone Number	512-225-7014
Cell Number	512-565-2012
Market Segment	Not applicable

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

Comments Received	
Comment Author	**Comment Summary**
Credit WG 111121	Noted NPRR1104 will provide positive credit impacts as it brings Protocols in line with current credit systems and more appropriately reflects the forward risk related to the RTLE calculation

Market Rules Notes

Please note that the following NPRRs also propose revisions to Section 16.11.4.3:

- NPRR1067, Market Entry Qualifications, Continued Participation Requirements, and Credit Risk Assessment
- NPRR1088, Applying Forward Adjustment Factors to Forward Market Positions and Un-applying Forward Adjustment Factors to Prior Market Positions

Proposed Protocol Language Revision

16.11.4.3 Determination of Counter-Party Estimated Aggregate Liability

(1) After a Counter-Party commences activity in ERCOT markets, ERCOT shall monitor and calculate the Counter-Party's EAL based on the formulas below.

EAL_q = **Max [IEL during the first 40-day period only beginning on the date that the Counter-Party commences activity in ERCOT markets, RFAF * Max {RTLE during the previous *lrq* days}, RTLF] + DFAF * DALE + Max [RTLCNS, Max {URTA during the previous *lrq* days}] + $\textbf{OUT}_q$ + $\textbf{ILE}_q$**

EAL_t = **Max [RFAF * Max {RTLE during the previous *lrt* days}, RTLF] + DFAF * DALE + Max [RTLCNS, Max {URTA during the previous *lrt* days}] + OUT_t**

EAL_a = **OUT_a**

ERCOT may adjust the number of days used in determining the highest RTLE and/or URTA, and/or to exclude specific Operating Days to calculate RTLE, URTA, OUT, or DALE.

The above variables are defined as follows:

Variable	Unit	Description
EAL_q	$	*Estimated Aggregate Liability for all the QSEs* represented by a Counter-Party if at least one QSE represented by the Counter-Party represents either Load or generation.
EAL_t	$	*Estimated Aggregate Liability for all the QSEs* represented by a Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation.
EAL_a	$	*Estimated Aggregate Liability for all the CRR Account Holders* represented by the Counter-Party.
IEL	$	*Initial Estimated Liability for all the QSEs* represented by the Counter-Party if at least one QSE represented by the Counter-Party represents either Load or generation as defined in paragraphs (1), (2), (3) and (4) of Section 16.11.4.2, Determination of Counter-Party Initial Estimated Liability.
q		QSEs represented by Counter-Party.
t		QSEs represented by a Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation
a		CRR Account Holders represented by Counter-Party.
RTLE	$	*Real Time Liability Extrapolated*—M1 multiplied by the sum of the net amount, with zero substituted for missing values, due to or from ERCOT by the Counter-Party in the 14 most recent Operating Days for which RTM Initial Statements are produced for Counter-Parties according to the ERCOT Settlement Calendar divided by 14.
URTA	$	*Unbilled Real-Time Amount*—M2 multiplied by the sum of the net amount, with zero substituted for missing values, due to or from ERCOT by the Counter-Party in the 14 most recent Operating Days for which RTM Initial Statements are produced for Counter-Parties according to the ERCOT Settlement Calendar divided by 14.
RTL	$	*Real-Time Liability*—The estimated or settled amounts due to or from ERCOT due to activities in the RTM for an Operating Day, as defined in Section 16.11.4.3.2, Real-Time Liability Estimate.
RTLCNS	$	*Real Time Liability Completed and Not Settled*—For each Operating Day that is completed but not settled, ERCOT shall calculate RTL adjusted up by *rtlcu%* if there is a net amount due to ERCOT or adjusted down by *rtlcd%* if there is a net amount due to the QSE. RTLCNS = Sum of Max RTL(*rtlcu%* * RTL, *rtlcd%* * RTL) for all completed and not settled Operating Days Where:

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Variable	Unit	Description
		rtlcu = Real-Time Liability Markup *rtlcd* = Real-Time Liability Markdown
RTLF	$	*Real-Time Liability Forward*— rtlfp% of the sum of estimated RTL from the most recent seven Operating Days. RTLF = *rtlf%* of the Sum of Max RTL(*rtlcu%* * RTL, *rtlcd%* * RTL) for the most recent seven Operating Days Where: *rtlfp* = Real-Time Liability Forward
OUT_q	$	*Outstanding Unpaid Transactions*—Outstanding unpaid transactions for all QSEs represented by the Counter-Party, which include (a) outstanding Invoices to the Counter-Party; (b) estimated unbilled items to the Counter-Party, to the extent not adequately accommodated in the RTLE calculation (including resettlements and other known liabilities); and (c) estimated CRR Auction revenue available for distribution for Operating Days in the previous two months, to the extent not invoiced to the Counter-Party. Invoices will not be considered outstanding for purposes of this calculation the Business Day after that Invoice payment is received. $\text{OUT}_q = \text{OIA}_q + \text{UDAA}_q + \text{UFA}_q + \text{UTA}_q + \text{CARD}$ Where: OIA_q = *Outstanding Invoice Amounts for all the QSEs represented by the Counter-Party* – Sum of any outstanding Real-Time and Day-Ahead unpaid invoices issued to the Counter-Party, including but not limited to CRR Auction Revenue Distribution (CARD) Invoices, CRR Balancing Account Invoices, Default Uplift Invoices and other miscellaneous Invoices. Also included are the amounts or portions of Invoices due to the Counter-Party that have been short-paid as a result of a default or non-payment of Invoices due to ERCOT by another Counter-Party. UDAA_q = *Unbilled Day-Ahead Amounts for all the QSEs represented by the Counter-Party* – Sum of DAL for all the QSEs represented by the Counter-Party for all Operating Days for which a DAM Statement is not generated. UFA_q = *Unbilled Final Amounts for all the QSEs represented by the Counter-Party* – Unbilled final extrapolated days (*ufd)* multiplied by the sum of the net amount due to or from ERCOT for all QSEs represented by the Counter-Party for Operating Days for which RTM Final Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM Final Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days. UTA_q = *Unbilled True-Up Amounts for all the QSEs represented by the Counter-Party* — Unbilled true-up extrapolated

Variable	Unit	Description
		days (*utd)* multiplied by the sum of the net amount due to or from ERCOT by the Counter-Party for all the QSEs represented by the Counter-Party for Operating Days for which RTM True-up Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM True-up Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days. CARD = *CRR Auction Revenue Distribution for all the QSEs represented by the Counter-Party* –Estimate of the Counter-Party's unpaid allocation of CRR Auction revenues that have already been collected but have not been paid out to all QSEs represented by the Counter-Party. CRR Auction revenues that have been earned but not billed are distributed based on the following Load Ratio Shares (LRSs): (a) Zonal LRS applied to revenues from CRRs cleared and have source and sink points located within a 2003 ERCOT Congestion Management Zone (CMZ), and (b) ERCOT-wide LRS applied to all other CRR Auction revenues. The LRS will be based on the latest completed operating month for which LRS are available.
DAL	$	*Day-Ahead Liability*—The estimated or settled amounts due to or from ERCOT due to activities in the DAM for an Operating Day, as defined in Section 16.11.4.3.1, Day-Ahead Liability Estimate.
OUT_t	$	*Outstanding Unpaid Transactions*—Outstanding unpaid transactions for all QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation, which include (a) outstanding Invoices to the Counter-Party; (b) estimated unbilled items to the Counter-Party, to the extent not adequately accommodated in the RTLE calculation (including resettlements and other known liabilities). $OUT_t = OIA_t + UDAA_t + UFA_t + UTA_t$ Where: OIA_t = *Outstanding Invoice Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation* – Sum of any outstanding Real-Time and Day-Ahead unpaid Invoices issued to the Counter-Party, including but not limited to CRR Balancing Account Invoices, Default Uplift Invoices and other miscellaneous Invoices. Also included are the amounts or portions of invoices due to the Counter-Party that have been short-paid as a result of a Default or non-payment of invoices due to ERCOT by another Counter-Party. $UDAA_t$ = *Unbilled Day-Ahead Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load*

Variable	Unit	Description
		or generation – Sum of DAL for all the QSEs represented by the Counter-Party for all Operating Days for which DAM Statement is not generated. UFA_t = *Unbilled Final Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation* – *ufd* multiplied by the sum of the net amount due to or from ERCOT for all QSEs represented by the Counter-Party for Operating Days for which RTM Final Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM Final Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days. UTA_t = *Unbilled True-Up Amounts for all the QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation* – *utd* multiplied by the sum of the net amount due to or from ERCOT by the Counter-Party for all the QSEs represented by the Counter-Party for Operating Days for which RTM True-up Statements were generated in the 21 most recent calendar days, divided by the number of Operating Days for which RTM True-up Settlement Statements were generated for the Counter-Party in the 21 most recent calendar days.
OUT_a	$	*Outstanding Unpaid Transactions for all CRR Account Holders represented by the Counter-Party*—Outstanding, unpaid transactions of all the CRR Account Holders represented by the Counter-Party, which include outstanding Invoices to the Counter-Party. Invoices will not be considered outstanding for purposes of this calculation the Business Day after that Invoice payment is received. $OUT_a = OIA_a + UDAA_a$ Where: OIA_a = *Outstanding Invoice Amounts for all the CRR Account Holders represented by the Counter-Party* – Sum of any outstanding Real-Time and Day-Ahead unpaid Invoices issued to the Counter-Party including but not limited to CRR Balancing Account Invoices, Default Uplift Invoices and other miscellaneous Invoices. Also included are the amounts or portions of Invoices due to the Counter-Party that have been short-paid as a result of a default or non-payment of Invoices due to ERCOT by another Counter-Party. $UDAA_a$ = *Unbilled Day-Ahead Amounts for all the CRR Account Holders represented by the Counter-Party* – Sum of DAL of all the CRR Account Holders represented by the Counter-Party for all Operating Days for which DAM Statement is not generated.

Variable	Unit	Description
ILE_q	$	*Incremental Load Exposure* –In the event of a Mass Transition necessitated by the default of a Counter-Party representing a QSE associated with an LSE, ERCOT may adjust the TPE of the Counter-Parties representing QSEs that are qualified as Providers of Last Resort (POLRs) to reflect the estimated Incremental Load Exposure (ILE) resulting from the Mass Transition. The adjustment will be based on the POLR's *pro rata* share of the defaulting Counter-Party's RTLE, based on the total estimated Electric Service Identifiers (ESI IDs) to be transitioned. ERCOT will communicate any such adjustment to the Authorized Representative of each Counter-Party who is a POLR within 24 hours of the initiation of a Mass Transition. The ILE adjustment will remain in place no more than the number of days necessary to effect a Mass Transition for the defaulting Counter-Party, after which time the incremental exposure will be fully reflected in the Counter-Party's unadjusted TPE.
DALE	$	*Average Daily Day-Ahead Liability Extrapolated*—M1 multiplied by the sum of the net amount, with zero substituted for missing values, due to or from ERCOT by the Counter-Party in the seven most recent Operating Days for which DAM Settlement Statements are produced for Counter-Parties according to the ERCOT Settlement Calendar divided by seven.
M1		M1 = M1a + M1b—Multiplier for DALE and RTLE. Provides for forward risk during a Counter-Party termination upon default based upon the sum of the time period required for any termination upon default (M1a) and the time period required for a Mass Transition only (M1b). The M1a component is applicable to all Counter-Parties. The M1b component is applicable only to Counter-Parties representing any QSE associated with a LSE. M1a = Time period required for any termination from an Operating Day. M1a is comprised of a fixed value (*M1d*), representing days from issuance of a collateral call to termination, and a calendar day-specific variable value. For any Operating Day, M1a is equal to the total number of forward calendar days encompassed by starting on the Operating Day, including *M1d* Bank Business Days forward, and adding any ERCOT holidays that are also Bank Business Days. M1b = Weighted average transition days = Min(B, (2 + Max(1, (u+1)/2))*(1-DF)), rounded up to whole days Where: u = (ESIn/r) Unscaled number of days to transition. B = Benchmark value. Used to establish a maximum M1 value. ESIn = Number of ESI IDs associated with an individual Counter-Party. This value will be updated no less often than annually by ERCOT and updated values communicated to individual Counter-Parties. Counter-Parties entering the market will provide an estimated number of ESI IDs for use during their first six months of market activity. Subsequent to this time, the value for that Counter-Party shall be updated by ERCOT concurrently with other Counter-Parties with QSEs representing an LSE.

Variable	Unit	Description
		r = Assumed ESI ID daily transition rate. DF = Discount Factor applied to M1b if the Counter-Party is eligible for unsecured credit under Section 16.11.2, Requirements for Setting a Counter-Party's Unsecured Credit Limit, or meets other creditworthiness standards that may be developed and approved by TAC and the ERCOT Board.
M2		Multiplier for URTA.
RFAF	None	*Real-Time Forward Adjustment Factor*—The adjustment factor for RTM-related forward exposure as defined in Section 16.11.4.3.3, Forward Adjustment Factors.
DFAF	None	*Day-Ahead Forward Adjustment Factor*—The adjustment factor for DAM-related forward exposure as defined in Section 16.11.4.3.3.
lrq	Days	Look-back period for RTM to find the maximum of RTLE or URTA for all QSEs represented by the Counter-Party if any of the QSEs represented by the Counter-Party represent either Load or generation.
lrt	Days	Look-back period for RTM to find the maximum of RTLE or URTA for all QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation.

The above parameters are defined as follows:

Parameter	Unit	Current Value*
rtlcu	Percentage	110%
rtlcd	Percentage	90%
rtlfp	Percentage	150%
ufd	Days	55
utd	Days	180
M1d	Days	8
B	Days	8
r	none	100,000 per day
DF	Percentage	0
M2	Days	9
lrq	Days	40
lrt	Days	20

Parameter	Unit	Current Value*
* The current value for the parameters referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

ERCOT Impact Analysis Report

NPRR Number	**1104**	**NPRR Title**	**As-Built Definition of Real Time Liability Extrapolated (RTLE)**
Impact Analysis Date	November 2, 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	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1105	NPRR Title	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 Protocols 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		Phase 1: Upon PUCT approval – December 17, 2021 (Sections 6.5.9.4.1 and 6.5.9.4.2) Phase 2: Upon system implementation (Section 6.5.7.3.1)	
Priority and Rank Assigned		Priority – 2022; Rank – 3020	
Nodal Protocol Sections Requiring Revision		6.5.7.3.1, Determination of Real-Time On-Line Reliability Deployment Price Adder 6.5.9.4.1, General Procedures Prior to EEA Operations 6.5.9.4.2, EEA Levels	
Related Documents Requiring Revision/Related Revision Requests		Nodal Operating Guide Revision Request (NOGRR) 236, Related to 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 Protocol Revision Request (NPRR) 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 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 NPRR 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.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1105 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 NPRR1105, and to grant NPRR1105 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 via roll call to recommend approval of NPRR1105 as amended by the 11/10/21 TCPA comments, and to forward to TAC NPRR1105 and the Impact Analysis. There was one opposing vote from the Consumer (Occidental) Market Segment, and six abstentions from the Consumer (OPUC), Cooperative (LCRA), IPM (Morgan Stanley), and Municipal (3) (Denton, Austin Energy, CPS Energy) Market Segments. All Market Segments participated in the votes.
Summary of PRS Discussion	On 11/10/21, participants reviewed NPRR1105 and the 11/8/21 STEC and 11/10/21 TCPA comments. Some participants expressed concern that the proposed language creates market distortions, additional voltage issues, and the potential for equipment damage. ERCOT Staff noted that requests for information are being sent to update ERCOT's understanding of TDSPs capabilities, and

	expressed support for the additional language proposed in the 11/8/21 STEC and 11/10/21 TCPA comments.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NPRR1105 as recommended by PRS in the 11/10/21 PRS Report with a recommended effective date of upon PUCT approval (12/17/21) for Phase 1 and a recommended priority of 2022 and rank of 3020 for Phase 2. There were two opposing votes from the IPM (Morgan Stanley) and IREP (Demand Control 2) Market Segments, and four abstentions from the Municipal (Garland, Denton, Austin Energy, CPS Energy) Market Segment. All Market Segments participated in the vote.
Summary of TAC Discussion	On 11/29/21, participants reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and the Revised Impact Analysis for NPRR1105. Participants discussed that NPRR1105 provides ERCOT with an optional tool prior to EEA. Some participants expressed concern that use of voltage reduction prior to EEA may negatively impact the system. Other participants expressed concern for impacts to Entities' Demand response programs, and whether voltage reduction measures would deliver meaningful relief depending on when it is deployed. Participants suggested TAC Action Items be added for ROS review of the effectiveness of using voltage reduction measures, and the criteria ERCOT uses to deploy voltage reduction measures prior to EEA, and for WMS to review costs of deployment. Participants voiced disappointment that NPRR1105 was published with insufficient time to identify and discuss issues before advancing the NPRR along an urgent timeline.
ERCOT Opinion	ERCOT supports approval of NPRR1105.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1105 and believe the market impact for NPRR1105 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 NPRR1105 as recommended by TAC in the 11/29/21 TAC Report.

Sponsor	
Name	Dan Woodfin

Board Report

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
TCPA 111021	Added distribution voltage reduction as part of Real-Time On-Line Reliability Deployment Price Adder and the Operating Reserve Demand Curve (ORDC); requested NPRR1105 be implemented at the same time as NPRR1006, Update Real-Time On-Line Reliability Deployment Price Adder Inputs to Match Actual Data
CPS Energy 112321	Raised concerns for Demand response programs in Municipally Owned Utilities (MOUs) and Non-Opt-In Entities (NOIEs)

Market Rules Notes

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

- NPRR1091, Changes to Address Market Impacts of Additional Non-Spin Procurement
    - Section 6.5.7.3.1
- NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3
    - Section 6.5.9.4.2

- NPRR1106, Deployment of Emergency Response Service (ERC) Prior to Declaration of Energy Emergency Alert (EEA)
  - Section 6.5.9.4.1
  - Section 6.5.9.4.2

Proposed Protocol Language Revision

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

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

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

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

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

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

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

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

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

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

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

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

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

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

(d) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

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

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

(e) Add the deployed MW from Load Resources other than Controllable Load Resources to GTBD linearly ramped over the ten-minute ramp period. The amount of deployed MW is calculated from the Resource telemetry and from applicable deployment instructions in Extensible Markup Language (XML) messages. ERCOT shall generate a linear bid curve defined by a price/quantity pair of $300/MWh for the first MW of Load Resources deployed and a price/quantity pair of $700/MWh for the last MW of Load Resources deployed in each SCED execution. After recall instruction, the amount of MW added to GTBD during the restoration period will be determined by validated telemetry. The TAC shall review the validity of the prices for the bid curve at least annually.

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

The above parameter is defined as follows:

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

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

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

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

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

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

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

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

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

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

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

[NPRR904, NPRR1006, NPRR1010, NPRR1014, and NPRR1093: Replace applicable portions of Section 6.5.7.3.1 above with the following upon system implementation for NPRR904, NPRR1006, NPRR1014, or NPRR1093; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.3.1 Determination of Real-Time Reliability Deployment Price Adder

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

(a) RUC-committed Resources, except for those whose QSEs have opted out of RUC Settlement in accordance with paragraph (12) of Section 5.5.2, Reliability Unit Commitment (RUC) Process;

(b) RMR Resources that are On-Line, including capacity secured to prevent an Emergency Condition pursuant to paragraph (2) of Section 6.5.1.1, ERCOT Control Area Authority;

(c) Deployed Load Resources other than Controllable Load Resources;

(d) Deployed Emergency Response Service (ERS);

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

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

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

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

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

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

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

(l) ERCOT-directed deployment of Transmission and/or Distribution Service Provider (TDSP) standard offer Load management programs; and

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

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

(a) For RUC-committed Resources with a telemetered Resource Status of ONRUC and for RMR Resources that are On-Line:

(i) Set the LSL and LDL to zero;

(ii) Remove all Ancillary Service Offers; and

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

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

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

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

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

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

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

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

(d) For all On-Line ESRs:

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

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

(e) For all Controllable Load Resources excluding ones with a telemetered status of OUTL:

(i) If the Controllable Load Resource SCED Base Point is not at LDL, set LDL to the greater of Aggregated Resource Output - (60 minutes *

Normal Ramp Rate down), or LSL; and

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

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

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

The above parameter is defined as follows:

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

(h) Add the MW from DC Tie imports during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator.

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

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

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

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

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

(n) Add the deployed MWs from TDSP standard offer Load management programs to GTBD, if ERCOT instructs TDSPs to deploy their standard offer Load management programs. The amount of deployed MW is the value ERCOT provided for all TDSP standard offer Load management programs in the most current May Report on Capacity, Demand and Reserves in the ERCOT Region, unless modified as specified in this paragraph. If ERCOT is informed that all or a portion of a TDSP's standard offer Load management program has been fully exhausted, or has been expanded as the result of a Public Utility Commission of Texas (PUCT) proceeding, ERCOT will remove the associated MW value of any exhausted capacity from the amount of deployed MW or, in the case of an expansion, ERCOT will request an updated MW value from the relevant TDSPs to use in place of the May Report on Capacity, Demand and Reserves in the

ERCOT Region value for that year. The initial value ERCOT will use for deployed MW under this paragraph for each calendar year, as well as any subsequent changes to this value, will be communicated to Market Participants in a Market Notice. After recall, an approximation of the amount of un-restored TDSP standard offer Load management programs shall be used. GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours") defined by item (g) above.

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

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

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

(r) The Real-Time Reliability Deployment Price Adder for Energy is equal to the positive difference between the System Lambda from item (q) above and the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of Section 6.5.7.3, Security Constrained Economic Dispatch.

(s) For each individual Ancillary Service, the Real-Time Reliability Deployment Price Adder for Ancillary Service is equal to the positive difference between the MCPC for that Ancillary Service from item (q) above and the MCPC for that Ancillary Service.

6.5.9.4.1 General Procedures Prior to EEA Operations

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

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

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

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

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

[NPRR863: Replace item (d) above with the following upon system implementation:]   (d) Utilize available Resources providing RRS, ECRS, and Non-Spin services as required;

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

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

6.5.9.4.2 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) At ERCOT's discretion, deploy available contracted ERS-30 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been deployed. The ERS-30 ramp period shall begin at the completion of the VDI.

(A) If less than 500 MW of ERS-30 is available for deployment, ERCOT shall deploy it as a single block.

(B) If the amount of ERS-30 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-30 as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS Resources in ERS-30 into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS Contract Period for ERS-30, ERCOT shall notify QSEs representing ERS Resources in ERS-30 of their ERS Resources' group assignments.

(C) ERS-30 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct their ERS Resources in 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-30 deployment or the ERS-30 Resources have reached their maximum deployment time.

(E) ERCOT shall notify QSEs of the release of ERS-30 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-30 has been recalled. The VDI shall represent the official notice of ERS-30 release. ERCOT may release ERS-30 as a block or by group designation.

(F) Upon release, an ERS Resource in ERS-30 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.

[NPRR1010: Insert paragraph (v) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(v) At ERCOT's discretion, manually deploy, through ICCP, available RRS and ECRS capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

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

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

(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.

[NPRR995 and NPRR1002: Insert applicable portions of paragraph (iii) below upon system implementation:]

(iii) Ensure that each of its ESRs and 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 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 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 available contracted ERS-10 Resources, undeployed ERS-30 and/or deploy RRS supplied from Load Resources (controlled by high-set under-frequency relays). ERCOT may deploy ERS-10, ERS-30, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

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

(iii) Instruct QSEs to deploy available contracted ERS-10 Resources, undeployed ERS-30, and/or deploy ECRS or RRS (controlled by high-set under-frequency relays) supplied from Load Resources. ERCOT may deploy ERS-10, ERS-30, ECRS, or RRS simultaneously or separately, and in any order. ERCOT shall issue such Dispatch Instructions in accordance with the deployment methodologies described in paragraphs (iv) and (v) below and, if deploying ERS-30, the methodologies described in paragraph (1)(a)(iv) above.

(iv) ERCOT shall deploy ERS-10 via an XML message followed by a VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been deployed. The ERS-10 ramp period shall begin at the completion of the VDI.

(A) If less than 500 MW of ERS-10 is available for deployment, ERCOT shall deploy all ERS-10 Resources as a single block.

(B) If the amount of ERS-10 available for deployment equals or exceeds 500 MW, ERCOT, at its discretion, may deploy ERS-10 Resources as a single block or by group designation. ERCOT shall develop a random selection methodology for determining how to place ERS-10 Resources into groups, and shall describe the methodology in a document posted to the ERCOT website. Prior to the start of an ERS-10 Contract Period, ERCOT shall notify QSEs representing ERS-10 Resources of their ERS-10 Resources' group assignments.

(C) ERS-10 may be deployed at any time in a Settlement Interval.

(D) Upon deployment, QSEs shall instruct ERS-10 Resources to perform at contracted levels consistent with the criteria described in Section 8.1.3.1.4 until ERCOT releases the ERS-10 deployment or the ERS-10 Resources have reached their maximum deployment times.

(E) ERCOT shall notify QSEs of the release of ERS-10 via an XML message followed by VDI to the all-QSE Hotline. ERCOT shall post a message electronically to the ERCOT website that ERS-10 has been recalled. The VDI shall represent the official notice of ERS-10 release. ERCOT may release ERS-10 as a block or by group designation.

(F) Upon release, an ERS-10 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.

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

[NPRR863: Replace paragraph (v) above with the following upon system implementation:]

(v) 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;

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

(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;

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

(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

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

(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 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.

[NPRR939 and NPRR1010: Replace applicable portions of paragraph (D) above with the following upon system implementation for NPRR939; and upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(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.

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

(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 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 TSPs and DSPs or their agents to shed firm Load, in 100 MW blocks, distributed as documented in the 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) In addition to measures associated with EEA Levels 1 and 2, TSPs and DSPs or their agents will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TSPs and DSPs or their agents shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

Revised ERCOT Impact Analysis Report

NPRR Number	1105	NPRR Title	Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
Impact Analysis Date	November 22, 2021		
Estimated Cost/Budgetary Impact	Between $80k and $120k		
Estimated Time Requirements	Phase 1: No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon Public Utility Commission of Texas (PUCT) prioritization and approval. Phase 2: The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 6 to 9 months See Comments		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 73% ERCOT; 27% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Market Operation Systems 55% • Data Management & Analytic Systems 32% • Energy Management Systems 14%		
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
Phase 1 will implement changes to the following Nodal Protocol sections: • 6.5.9.4.1, General Procedures Prior to EEA Operations

- 6.5.9.4.2, EEA Levels

Phase 2 will implement changes to the following Nodal Protocol section:

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

Board Report

NPRR Number	**1106**	**NPRR Title**	**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 Public Utility Commission of Texas (PUCT) approval – December 17, 2021		
Priority and Rank Assigned	Not Applicable		
Nodal Protocol Sections Requiring Revision	2.1, Definitions 3.14.3, Emergency Response Service 6.5.9.4.1, General Procedures Prior to EEA Operations 6.5.9.4.2, EEA Levels 6.5.9.4.3, Restoration of Market Operations 8.1.3.1.3.1, Time Period Availability Calculations for Emergency Response Service Loads 8.1.3.1.3.2, Time Period Availability Calculations for Emergency Response Service Generators		
Related Documents Requiring Revision/Related Revision Requests	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 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 Protocol Revision Request (NPRR) revises the Protocols to allow for the deployment of ERS prior to the declaration of an Energy Emergency Alert (EEA) 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).
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 [X] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*
Business Case	In 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 the Order Granting Exception 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 is revising the ERS Request for Proposal (RFP) and ERS Technical Requirements & Scope of Work to make clear that ERS procured on a going forward basis may be deployed prior to EEA. These changes will be effective starting with ERS procured for the December 2021 to March 2022 Standard Contract Term. The revisions proposed in this NPRR are necessary to clarify that, pursuant to the good cause exception granted by the PUCT, ERS may deploy ERS prior to declaration of an EEA. More specifically, the proposed revisions grant ERCOT Operators the discretion to deploy ERS 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.
Credit Work Group Review	ERCOT Credit Staff and the Credit Work Group (Credit WG) have reviewed NPRR1106 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 NPRR1106, and to grant NPRR1106 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 via roll call to recommend approval of NPRR1106 as submitted, and to forward to TAC NPRR1106 and the Impact Analysis. There was one opposing vote from the IPM (Morgan Stanley) Market Segment, and one abstention from the Municipal (Austin Energy) Market Segment. All Market Segments participated in the votes.
Summary of PRS Discussion	On 11/10/21, ERCOT Staff reviewed NPRR1106.
TAC Decision	On 11/29/21, TAC voted via roll call to recommend approval of NPRR1106 as recommended by PRS in the 11/10/21 PRS Report with a recommended effective date of upon PUCT approval (12/17/21). There was one opposing vote from the 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 NPRR1106.
ERCOT Opinion	ERCOT supports approval of NPRR1106.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1106 and believes the market impact for NPRR1106 enhances ERCOT's operational tools to address potential reliability outcomes by granting ERCOT Operators the discretion to deploy ERS 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.
Board Decision	On 12/10/21, the ERCOT Board recommended approval of NPRR1106 as recommended by TAC in the 11/29/21 TAC Report.

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Board Report

Market Segment	Not Applicable

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

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

- NPRR1090, ERS Winter Storm Uri Lessons Learned Changes and Other ERS Items (unboxed 12/1/21)
  - Section 8.1.3.1.3.1
  - Section 8.1.3.1.3.2

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

- NPRR1094, Allow Under Frequency Relay Load to be Manually Shed During EEA3
  - Section 6.5.9.4.2
- NPRR1105, Option to Deploy Distribution Voltage Reduction Measures Prior to Energy Emergency Alert (EEA)
  - Section 6.5.9.4.1
  - Section 6.5.9.4.2

Proposed Protocol Language Revision

2.1 DEFINITIONS

Emergency Response Service (ERS)

An emergency service consistent with P.U.C. SUBST. R. 25.507, Electric Reliability Council of Texas (ERCOT) Emergency Response Service (ERS), used to assist in maintaining or restoring ERCOT System frequency. ERS is not an Ancillary Service.

3.14.3 Emergency Response Service

(1) ERCOT shall procure and deploy ERS with the goal of promoting reliability prior to and during energy emergencies.

6.5.9.4.1 General Procedures Prior to EEA Operations

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

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

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

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

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

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

(d) Utilize available Resources providing RRS, 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. ***6.5.9.4.2 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 ERS-10 and ERS-30.

[NPRR1010: Insert paragraph (v) below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(iv) At ERCOT's discretion, manually deploy, through ICCP, available RRS and ECRS capacity from Generation Resources having a Resource Status of ONSC and awarded RRS or ECRS.

(b) QSEs shall:

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

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

(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.

[NPRR995 and NPRR1002: Insert applicable portions of paragraph (iii) below upon system implementation:]

(iii) Ensure that each of its ESRs and 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 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 DSPs or their agents to reduce Customer Load by using distribution voltage reduction measures, if deemed beneficial by the TSP, DSP, or their agents.

(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.

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

(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.

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

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

(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;

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

(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;

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

(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

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

(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 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.

[NPRR939 and NPRR1010: Replace applicable portions of paragraph (D) above with the following upon system implementation for NPRR939; and upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

(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.

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

(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 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 TSPs and DSPs or their agents to shed firm Load, in 100 MW blocks, distributed as documented in the 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) In addition to measures associated with EEA Levels 1 and 2, TSPs and DSPs or their agents will keep in mind the need to protect the safety and health of the community and the essential human needs of the citizens. Whenever possible, TSPs and DSPs or their agents shall not manually drop Load connected to under-frequency relays during the implementation of the EEA.

6.5.9.4.3 Restoration of Market Operations

(1) ERCOT shall continue the EEA until sufficient offers are received and deployed by ERCOT to eliminate the conditions requiring the EEA and normal SCED operations are restored. After restoring RRS, ERCOT shall restore curtailed DC Tie Load. Intermittent solutions of SCED do not set new LMPs until ERCOT declares that the EEA is no longer needed.

8.1.3.1.3.1 Time Period Availability Calculations for Emergency Response Service Loads

(1) For an ERS Load on an ERS Default Baseline, ERCOT will calculate its ERSAF as follows:

(a) ERCOT will consider the ERS Load to have been unavailable for a 15-minute interval in a contracted ERS Time Period in which any of the following apply: