MWSNAP $_{ruc,\ q,\ h,\ r}$	MW	*Calculated MW required to support ESR's calculated Ancillary Service coverage at Snapshot*—The MW discharge (positive) or charge (negative) required to support the ESR's calculated Ancillary Service coverage considering the submitted COP values for Hour Beginning Planned SOC, MinSOC, MaxSOC and the difference in the Hour Beginning Planned SOC for the hour under consideration and the next hour while accounting for Ancillary Service deployment factors and the duration requirements for energy and different Ancillary Service types Position for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
ESRASSNAP $_{ruc,\ q,\ h}$	MW	*Calculated Ancillary Service MW Capacity Provided By QSE's ESR Portfolio at Snapshot*—The total ESR MW capacity used to cover the QSE *q's* Upward Ancillary Service position for Reg-Up, RRS, ECRS, and Non-Spin in the RUC Snapshot for the RUC process *ruc*, for the hour *h* that includes the 15-minute Settlement Interval.
ESRMWSNAP $_{ruc,\ q,\ h}$	MW	*Calculated QSE Total ESR MW Discharging or Charging Required To Support Ancillary Service at Snapshot*—The total net ESR MW discharging or charging required to cover the QSE *q's* Ancillary Service position provided by the QSE ESR portfolio in the RUC Snapshot for the RUC process *ruc*, for the hour *h* that includes the 15-minute Settlement Interval, taking into account the COP SOC values from COP.
~~ASCAP1SNAP~~ $\cancel{_{ruc,\ q,\ i}}$	~~MW~~	~~*Ancillary Service Net Capacity Level 1 at Snapshot*—The net capacity for Reg-Up for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.~~
~~ASCAP2SNAP~~ $\cancel{_{ruc,\ q,\ i}}$	~~MW~~	~~*Ancillary Service Net Capacity Level 2 at Snapshot*—The net capacity for RRS for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.~~
~~ASCAP3SNAP~~ $\cancel{_{ruc,\ q,\ i}}$	~~MW~~	~~*Ancillary Service Net Capacity Level 3 at Snapshot*—The net capacity for Reg-Up and RRS for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.~~
~~ASCAP4SNAP~~ $\cancel{_{ruc,\ q,\ i}}$	~~MW~~	~~*Ancillary Service Net Capacity Level 4 at Snapshot*—The net capacity for Reg-Up, RRS, and ECRS for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.~~
~~ASCAP5SNAP~~ $\cancel{_{ruc,\ q,\ i}}$	~~MW~~	~~*Ancillary Service Net Capacity Level 5 at Snapshot*—The net capacity for Reg-Up, RRS, ECRS, and Non-Spinning Reserve (Non-Spin) for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.~~
~~ASCAP6SNAP~~ $\cancel{_{ruc,\ q,\ i}}$	~~MW~~	~~*Ancillary Service Net Capacity Level 6 at Snapshot*—The net capacity for Reg-Down for QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.~~

~~ASOFR1SNAP~~ $_{ruc,\,q,\,r,\,h}$	~~MW~~	~~*Ancillary Service Offer Level 1 at Snapshot*—The capacity represented by validated Reg-Up Ancillary Service Offers for Resource *r* represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR2SNAP~~ $_{ruc,\,q,\,r,\,h}$	~~MW~~	~~*Ancillary Service Offer Level 2 at Snapshot*—The capacity represented by validated RRS Ancillary Service Offers for Resource *r* represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR3SNAP~~ $_{ruc,\,q,\,r,\,h}$	~~MW~~	~~*Ancillary Service Offer Level 3 at Snapshot*—The capacity represented by validated Reg-Up and RRS Ancillary Service Offers for Resource *r* represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR4SNAP~~ $_{ruc,\,q,\,r,\,h}$	~~MW~~	~~*Ancillary Service Offer Level 4 at Snapshot*—The capacity represented by validated Reg-Up, RRS, and ECRS Ancillary Service Offers for Resource *r* represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR5SNAP~~ $_{ruc,\,q,\,r,\,h}$	~~MW~~	~~*Ancillary Service Offer Level 5 at Snapshot*—The capacity represented by validated Reg-Up, RRS, ECRS, and Non-Spin Ancillary Service Offers for Resource *r* represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~

~~ASOFR6SNAP $_{ruc, q, r, h}$~~	~~MW~~	~~Ancillary Service Offer Level 6 at Snapshot—The capacity represented by validated Reg-Down Ancillary Service Offers for Resource r represented by QSE q according to the RUC Snapshot for the RUC process ruc for the hour h that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource r is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour h.~~
RUCOSFADJ $_{ruc, q, i}$	MW	*RUC Overall Shortfall at End of Adjustment Period*—The QSE *q's* overall capacity shortfall at the end of the Adjustment Period, including capacity from IRRs as seen in the RUC Snapshot for the RUC process *ruc*, for the 15-minute Settlement Interval *i*.
RUCASFADJ $_{q, i}$	MW	*RUC Ancillary Service Shortfall at End of Adjustment Period*—The QSE *q's* Ancillary Service capacity shortfall at the end of the Adjustment Period for the 15-minute Settlement Interval *i*.
ASONPOSADJ $_{q, i}$	MW	*Ancillary Service On-Line Position at End of Adjustment Period*—The QSE *q's* total On-Line Ancillary Service position at the end of the Adjustment Period for the 15-minute Settlement Interval *i*.
RUPOSADJ $_{q, h}$	MW	*Regulation Up Position at End of Adjustment Period*—The QSE *q's* net positive Reg-Up Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
RRPOSADJ $_{q, h}$	MW	*Responsive Reserve Service Position at End of Adjustment Period*—The QSE *q's* net positive RRS Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
ECRPOSADJ $_{q, h}$	MW	*ERCOT Contingency Reserve Service Position at End of Adjustment Period*—The QSE *q's* net positive ECRS Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
NSPOSADJ $_{q, h}$	MW	*Non-Spin Reserve Service Position at End of Adjustment Period*—The QSE *q's* net positive Non-Spin Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
RDPOSADJ $_{q, h}$	MW	*Regulation Down Position at End of Adjustment Period*—The QSE *q's* net positive Reg-Down Ancillary Service Position at the end of the Adjustment period for the hour *h* that includes the 15-minute Settlement Interval.
ASOFFOFRADJ $_{q, r, h}$	MW	*Ancillary Service Offline Offers at End of Adjustment Period*—The capacity represented by validated Ancillary Service Offers for ~~ECRS and~~ Non-Spin for Resource *r* with COP status of "OFF", represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.

ASOFRLRADJ $_{q, r, h}$	MW	*Ancillary Service Offer per Load Resource at End of Adjustment Period* – The capacity represented by validated Ancillary Service Offers for Reg-Up, Non-Spin, RRS, and ECRS for the Load Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.
~~ASCAP1ADJ $_{q, i}$~~	~~MW~~	~~*Ancillary Service Net Capacity Level 1 at End of Adjustment Period* —The net capacity at the end of the Adjustment Period for Reg-Up for QSE *q*, for the 15-minute Settlement Interval *i*.~~
~~ASCAP2ADJ $_{q, i}$~~	~~MW~~	~~*Ancillary Service Net Capacity Level 2 at End of Adjustment Period* —The net capacity at the end of the Adjustment Period for RRS for QSE *q*, for the 15-minute Settlement Interval *i*.~~
~~ASCAP3ADJ $_{q, i}$~~	~~MW~~	~~*Ancillary Service Net Capacity Level 3 at End of Adjustment Period* —The net capacity at the end of the Adjustment Period for Reg-Up and RRS for QSE *q*, for the 15-minute Settlement Interval *i*.~~
~~ASCAP4ADJ $_{q, i}$~~	~~MW~~	~~*Ancillary Service Net Capacity Level 4 at End of Adjustment Period* —The net capacity at the end of the Adjustment Period for Reg-Up, RRS, and ECRS for QSE *q*, for the 15-minute Settlement Interval *i*.~~
~~ASCAP5ADJ $_{q, i}$~~	~~MW~~	~~*Ancillary Service Net Capacity Level 5 at End of Adjustment Period* —The net capacity at the end of the Adjustment Period for Reg-Up, RRS, ECRS, and Non-Spin for QSE *q*, for the 15-minute Settlement Interval *i*.~~
~~ASCAP6ADJ $_{q, i}$~~	~~MW~~	~~*Ancillary Service Net Capacity Level 6 at End of Adjustment Period* —The net capacity at the end of the Adjustment Period for Reg-Down for QSE *q*, for the 15-minute Settlement Interval *i*.~~
~~ASOFR1ADJ $_{q, r, h}$~~	~~MW~~	~~*Ancillary Service Offer Level 1 at End of Adjustment Period* —The capacity represented by validated Reg-Up Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR2ADJ $_{q, r, h}$~~	~~MW~~	~~*Ancillary Service Offer Level 2 at End of Adjustment Period* —The capacity represented by validated RRS Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~

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~~ASOFR3ADJ $_{q, r, h}$~~	~~MW~~	~~*Ancillary Service Offer Level 3 at End of Adjustment Period*—The capacity represented by validated Reg-Up and RRS Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR4ADJ $_{q, r, h}$~~	~~MW~~	~~*Ancillary Service Offer Level 4 at End of Adjustment Period*—The capacity represented by validated Reg-Up, RRS, and ECRS Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR5ADJ $_{q, r, h}$~~	~~MW~~	~~*Ancillary Service Offer Level 5 at End of Adjustment Period*—The capacity represented by validated Reg-Up, RRS, ECRS, and Non-Spin Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
~~ASOFR6ADJ $_{q, r, h}$~~	~~MW~~	~~*Ancillary Service Offer Level 6 at End of Adjustment Period*—The capacity represented by validated Reg-Down Ancillary Service Offers for Resource *r* represented by QSE *q* at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.~~
PFPOSADJ $_{q, h}$	MW	*Responsive Reserve (Governor Response or Governor-Like Response) Position at End of Adjustment Period*—The QSE *q's* net RRS-PFR Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
UFPOSADJ $_{q, h}$	MW	*Responsive Reserve (Under Frequency trigger at 59.7 Hz.) Position at End of Adjustment Period*—The QSE *q's* net RRS-UFR Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.

FFPOSADJ $_{q, h}$	MW	*Responsive Reserve (Fast Frequency Response) Position at End of Adjustment Period*—The QSE *q's* net positive RRS-FFR Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
ECSPOSADJ $_{q, h}$	MW	*ERCOT Contingency Reserve Service (SCED Dispatchable) Position at End of Adjustment Period*—The QSE *q's* net ECRS SCED Dispatchable Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
ECMPOSADJ $_{q, h}$	MW	*ERCOT Contingency Reserve Service (Non-SCED Dispatchable) Position at End of Adjustment Period*—The QSE *q's* net positive ECRS non-SCED-dispatchable Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
NSSPOSADJ $_{q, h}$	MW	*Non-Spin Reserve Service (SCED Dispatchable) Position at End of Adjustment Period*—The QSE *q's* net Non-Spin SCED-dispatchable Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
NSMPOSADJ $_{q, h}$	MW	*Non-Spin Reserve Service (Non-SCED Dispatchable) Position at End of Adjustment Period*—The QSE *q's* net positive Non-Spin non-SCED-dispatchable Ancillary Service Position at the end of the Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
ASMWCAPUQADJ $_{q, h}$	MW	*Calculated Total MW Capacity used to cover the QSE's Ancillary Service Position at End of Adjustment Period*—The calculated total MW capacity for a QSE *q* that represents the amount of the QSE's Ancillary Service Position covered by its Resources at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
ASMWCAPUADJ $_{q, h, ASSubtype, r}$	MW	*Calculated MW Capacity used to cover the QSE's 'AStype' Ancillary Service Position at End of Adjustment Period*—The calculated MW ~~C~~capacity of a Resource *r* represented by QSE *q* that is used to cover its QSE's "ASSubtype" Ancillary Service Position at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
MWADJ $_{q, h, r}$	MW	*Calculated MW discharge (positive) or charge (negative) required to support ESR's calculated Ancillary Service coverage at End of Adjustment Period*—The MW discharge (positive) or charge (negative) required to support the ESR's calculated Ancillary Service coverage considering the submitted COP values for Hour Beginning Planned SOC, MinSOC, MaxSOC and the difference in the Hour Beginning Planned SOC for the hour under consideration and the next hour while accounting for Ancillary Service deployment factors and the duration requirements for energy and different Ancillary Service types Position at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.

ESRASADJ $_{q,h}$	MW	*Calculated Ancillary Service MW Capacity Provided By QSE's ESR Portfolio at the End of Adjustment Period*—The total ESR MW capacity used to cover the QSE *q's* Upward Ancillary Service position for Reg-Up, RRS, ECRS, and Non-Spin at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
ESRMWADJ $_{q,h}$	MW	*Calculated QSE Total ESR MW Discharging or Charging Required To Support Ancillary Service at End of Adjustment Period*—The total net ESR MW discharging or charging required to cover the QSE *q's* Ancillary Service position provided by the QSE ESR portfolio at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval, taking into account the COP SOC values from COP.
RTAML $_{q,p,i}$	MWh	*Real-Time Adjusted Metered Load*—The QSE *q*'s Adjusted Metered Load (AML) at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
RUCCAPSNAP $_{ruc,q,i}$	MW	*RUC Capacity Snapshot at time of RUC*—The amount of the QSE *q*'s calculated capacity in the RUC Snapshot for the RUC process *ruc* for a 15-minute Settlement Interval *i*.
RCAPSNAP $_{ruc,q,r,h}$	MW	*Resource Capacity at Snapshot*—The available capacity of Generation Resource ~~or ESR~~ *r* represented by the QSE *q*, according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. For ~~ESRs and~~ Generation Resources that are not IRRs, the available capacity shall be equal to HSL. For WGRs and PVGRs, the available capacity shall be equal to the lesser of the HSL or the WGRPP and the PVGRPP, respectively. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
DCIMPSNAP $_{ruc,q,p,i}$	MW	*DC Import at Snapshot*—The approved aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
RTDCIMP $_{q,p}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated final, approved DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval.
RUCCPSNAP $_{ruc,q,h}$	MW	*RUC Capacity Purchase at Snapshot*—The QSE *q*'s capacity purchase, according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
RUCCSSNAP $_{ruc,q,h}$	MW	*RUC Capacity Sale at Snapshot*—The QSE *q*'s capacity sale, according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
RUCCAPADJ $_{q,i}$	MW	*RUC Capacity at End of Adjustment Period*—The amount of the QSE *q*'s calculated capacity, excluding capacity for IRRs, at the end of the Adjustment Period for a 15-minute Settlement Interval *i*.
RCAPADJ $_{q,r,h}$	MW	*Resource Capacity at End of Adjustment Period*—The HSL of a non-IRR Generation Resource ~~or ESR~~ *r* represented by the QSE *q* at the end of the Adjustment Period, for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

RUCCPADJ $_{q,h}$	MW	*RUC Capacity Purchase at End of Adjustment Period*—The QSE *q*'s capacity purchase, at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
RUCCSADJ $_{q,h}$	MW	*RUC Capacity Sale at End of Adjustment Period*—The QSE *q*'s capacity sale, at the end of Adjustment Period for the hour *h* that includes the 15-minute Settlement Interval.
DAEP $_{q,p,h}$	MW	*Day-Ahead Energy Purchase*—The QSE *q*'s energy purchased in the DAM at the Settlement Point *p* for the hour *h* that includes the 15-minute Settlement Interval.
DAES $_{q,p,h}$	MW	*Day-Ahead Energy Sale*—The QSE *q*'s energy sold in the DAM at the Settlement Point *p* for the hour *h* that includes the 15-minute Settlement Interval.
RTQQEPSNAP $_{ruc,q,p,i}$	MW	*Real-Time QSE-to-QSE Energy Purchase at Snapshot*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the RUC Snapshot for the RUC process *ruc*.
RTQQESSNAP $_{ruc,q,p,i}$	MW	*Real-Time QSE-to-QSE Energy Sale at Snapshot*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the RUC Snapshot for the RUC process *ruc*.
RTQQEPADJ $_{q,p,i}$	MW	*Real-Time QSE-to-QSE Energy Purchase at End of Adjustment Period*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, at the end of the Adjustment Period for that Settlement Interval.
RTQQESADJ $_{q,p,i}$	MW	*Real-Time QSE-to-QSE Energy Sale at End of Adjustment Period*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, at the end of the Adjustment Period for that Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource, an ESR, or a Load Resource.
ASSubType	none	Ancillary Service Sub-Type: Reg-Up, Reg-Down, RRS provided as Primary Frequency Response, RRS provided via a high-set under-frequency relay, Fast Frequency Response (FFR), ECRS that is SCED-dispatchable, ECRS that is non-SCED dispatchable, Non-Spin that is SCED-dispatchable, and Non-Spin that is non-SCED-dispatchable.
z	none	A previous RUC process for the Operating Day.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
ruc	none	The RUC process for which this RUC Shortfall Ratio Share is calculated.

ERCOT Impact Analysis Report

NPRR Number	1236	NPRR Title	RTC+B Modifications to RUC Capacity Short Calculations
Impact Analysis Date	June 4, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon implementation of PR447, Real-Time Co-Optimization (RTC). See Comments.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NPRR beyond what was captured in PR447, Real-Time Co-optimization.

Board Report

NPRR Number	1237	**NPRR Title**	**Retail Market Qualification Testing Requirements**

Date of Decision	October 10, 2024
Action	Recommended Approval
Timeline	Normal
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval
Priority and Rank Assigned	Not applicable
Nodal Protocol Sections Requiring Revision	19.8, Retail Market Testing
Related Documents Requiring Revision/Related Revision Requests	None
Revision Description	This Nodal Protocol Revision Request (NPRR) provides conditions in which ERCOT requires all Competitive Retailers (CRs), new and existing, and Transmission and/or Distribution Service Providers (TDSPs) to successfully complete retail market qualification testing.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements

Board Report

	☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR documents the scenarios in which Market Participants are required to successfully complete retail qualification testing regardless of whether Market Participants previously received their qualification letter from ERCOT as a result of prior retail flight testing. As part of ERCOT's Texas Standard Electronic Transaction (SET) V5.0 project market communications, on May 8, 2024 ERCOT issued a Market Notice stating retail market qualification testing requirements that are not specifically outlined in the Protocols. Memorializing these scenarios into Section 19.8 may prevent future disagreements between ERCOT and Market Participants, since this retail qualification testing is mandatory in order that Market Participants can maintain their eligibility to serve Customers in the ERCOT Market. This requirement applies to all Market Participants regardless of if they are a new entrant or an existing entity.
PRS Decision	On 7/18/24, PRS voted unanimously to table NPRR1237 and refer the issue to RMS. All Market Segments participated in the vote. On 8/8/24, PRS voted unanimously to recommend approval of NPRR1237 as amended by the 8/6/24 RMS comments. All Market Segments participated in the vote. On 9/12/24, PRS voted unanimously to endorse and forward to TAC the 8/8/24 PRS Report and 8/27/24 Impact Analysis for NPRR1237. All Market Segments participated in the vote.
Summary of PRS Discussion	On 7/18/24, the sponsor provided an overview of NPRR1237. Participants requested that NPRR1237 be tabled and referred to RMS. On 8/8/24, PRS reviewed the 8/6/24 RMS comments. On 9/12/24, PRS reviewed the 8/27/24 Impact Analysis.
TAC Decision	On 9/19/24, TAC voted unanimously to recommend approval of NPRR1237 as recommended by PRS in the 9/12/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 9/19/24, there was no additional discussion beyond TAC review of the items below.

Board Report

TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NPRR1237 as recommended by TAC in the 9/19/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1237 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1237.
ERCOT Opinion	ERCOT supports approval of NPRR1237.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1237 and believes that it provides a positive market impact by offering general improvements by providing conditions in which ERCOT requires all CRs, new and existing, and TDSPs to successfully complete retail market qualification testing.

Sponsor	
Name	Kathy Scott
E-mail Address	Kathy.Scott@CenterPointEnergy.com
Company	CenterPoint Energy
Phone Number	713-582-8654
Cell Number	713-582-8654
Market Segment	Investor Owned Utility (IOU)

Board Report

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

Comments Received	
Comment Author	**Comment Summary**
RMS 080624	Endorsed NPRR1237 as revised by RMS

Market Rules Notes

None

Proposed Protocol Language Revision

19.8 Retail Market Testing

(1) The Texas Standard Electronic Transaction (TX SET) Working Group works with the ERCOT flight administrator to develop and maintain a test plan and related testing standards for all retail transactional changes within the ERCOT market.

(2) ~~There are events in the retail market where market-facing, Technical Advisory Committee (TAC) subcommittee-approved changes require~~ Market Participants may be required to successfully test as a means of confirming that each Market Participant is qualified to transmit TX SET transactions ~~under the new standards~~ as a result of approved changes prior to production implementation. Some of these changes include, but may not be limited to:

(a) North American Energy Standards Board (NAESB) Practice Standards version upgrade(s) as outlined in the TDTMS NAESB Electronic Delivery Mechanism V 1.6 Implementation Guide; and/or

(b) TX SET version release upgrade(s) as outlined in the Texas Standard Electronic Transaction Implementation Guides.

(3) ERCOT may also deem testing to be necessary by Market Participants in order that ERCOT may maintain ~~mission critical~~ retail systems' performance, reliability and integrity as outlined in the Retail and ListServ Market IT Services Service Level Agreement and the Market Data Transparency Service Level Agreement.

(4) Testing of these changes ~~is~~ shall be scheduled by ERCOT with approval by impacted Market Participants to allow ERCOT and all impacted Market Participants adequate time

to modify their systems and participate in the testing process. Testing processes, procedures, schedules and success criteria are defined in the Texas Market Test Plan (TMTP) Guide and on the ERCOT website. The ERCOT flight administrator is the final authority on all levels of retail business process qualification among trading partners.

(~~2~~5) ERCOT may enlist the services of an Independent Third Party Testing Administrator (ITPTA) for ~~this~~ testing retail processes.

(6) For additional testing requirements for both new and existing Market Participants, please refer to the Texas Market Test Plan.

ERCOT Impact Analysis Report

NPRR Number	**1237**	**NPRR Title**	**Retail Market Qualification Testing Requirements**
Impact Analysis Date	August 27, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	<u>**1244**</u>	**NPRR Title**	**Clarification of Controllable Load Resource Primary Frequency Response Responsibilities**
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: Between $70k and $100k Project Duration: 5 to 7 months		
Proposed Effective Date	Upon system implementation		
Priority and Rank Assigned	Priority – 2026; Rank – 4710		
Nodal Protocol Sections Requiring Revision	3.6.1, Load Resource Participation 6.5.7.5, Ancillary Services Capacity Monitor 8.5.2.1, ERCOT Required Primary Frequency Response		
Related Documents Requiring Revision/Related Revision Requests	Nodal Operating Guide Revision Request (NOGRR) 263, Related to NPRR1244, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities		
Revision Description	This Nodal Protocol Revision Request (NPRR) aligns provisions regarding eligibility of a Controllable Load Resource that is not providing Primary Frequency Response ("PFR") to provide ERCOT Contingency Reserve Service (ECRS), and the calculation of Physical Responsive Capability (PRC) to include only the capacity of Controllable Load Resources when they are qualified to provide Regulation Service and/or Responsive Reserve (RRS) which requires the Controllable Load Resource to be capable of providing PFR.		
Reason for Revision	☐ <u>Strategic Plan</u> Objective 1 – Be an industry leader for grid reliability and resilience ☐ <u>Strategic Plan</u> Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers		

Board Report

	☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR aligns the Nodal Protocols with NOGRR263, which clarifies Nodal Operating Guides to enable a Load Resource to register as a Controllable Load Resource even if it is not capable of providing PFR. This NPRR maintains existing provisions that require a Controllable Load Resource to be capable of providing PFR in order to be eligible to provide Regulation Service and/or RRS but eliminates this requirement as to a Controllable Load Resource that provides ECRS. This change will remove a disincentive for a Load Resource to register as a Controllable Load Resource since current provisions would eliminate the ability of the Load Resource to provide ECRS just because it registered as a Controllable Load Resource. These changes allow additional Load Resources to register as Controllable Load Resources and thereby provide ERCOT greater visibility and control over such Load Resources.
PRS Decision	On 8/8/24, PRS voted unanimously to recommend approval of NPRR1244 as submitted. All Market Segments participated in the vote. On 9/12/24, PRS voted unanimously to endorse and forward to TAC the 8/8/24 PRS Report as revised by PRS and 9/6/24 Impact Analysis for NPRR1244 with a recommended priority of 2025 and rank of 4530. All Market Segments participated in the vote.
Summary of PRS Discussion	On 8/8/24, PRS reviewed NPRR1244 and referenced NOGRR263 at ROS. On 9/12/24, PRS reviewed the 9/6/24 Impact Analysis and revised the title of NPRR1244 in response to ROS retitling NOGRR263 at their September 9, 2024 meeting. ERCOT Staff clarified that NPRR1244 is not dependent on NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources.

Board Report

TAC Decision	On 9/19/24, TAC voted unanimously to recommend approval of NPRR1244 as recommended by PRS in the 9/12/24 PRS Report; and the 9/13/24 Revised Impact Analysis; with a recommended priority of 2026 and rank of 4710. All Market Segments participated in the vote.
Summary of TAC Discussion	On 9/19/24, participants reviewed the 9/13/24 Revised Impact Analysis and reprioritized implementation to occur after the Real-Time Co-Optimization (RTC) project is completed.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NPRR1244 as recommended by TAC in the 9/19/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1244 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1244.
ERCOT Opinion	ERCOT supports approval of NPRR1244.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1244 and believes that it provides a positive market impact to enable a Load Resource to register as a Controllable Load Resource even if it is not capable of providing PFR. Specifically, this NPRR enables Controllable Load Resources that are not capable of providing PFR to be eligible to provide ECRS and Non-Spinning Reserve (Non-Spin). A Controllable Load Resource that is capable of providing PFR will continue to be required to respond to frequency disturbances with a Governor droop.

Board Report

Sponsor	
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Market Segment	Independent Retail Electric Provider (IREP)

Market Rules Staff Contact	
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Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

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

- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
    - Section 3.6.1
    - Section 6.5.7.5
- NPRR1235, Dispatchable Reliability Reserve Service as a Stand-Alone Ancillary Service
    - Section 6.5.7.5
- NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
    - Section 3.6.1

Proposed Protocol Language Revision

3.6.1 Load Resource Participation

Commented [JT1]: Please note NPRR1188 and NPRR1246 also propose revisions to this section.

Board Report

(1) A Load Resource may participate by providing:

(a) Ancillary Service:

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

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

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

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

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

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

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

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

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

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

(d) Voluntary Load response in Real-Time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6.5.7.5 Ancillary Services Capacity Monitor

Commented [JT2]: Please note NPRRs 1188 and 1235 also propose revisions to this section.

(1) ERCOT shall calculate the following every ten seconds and provide Real-Time summaries to ERCOT Operators and all Market Participants using ICCP, giving updates of calculations every ten seconds, and posting on the ERCOT website, giving updates of calculations every five minutes, which show the Real-Time total system amount of:

(a) RRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

(iv) Resources capable of Fast Frequency Response (FFR);

(b) Ancillary Service Resource Responsibility for RRS from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

(iv) Resources capable of FFR;

(c) ECRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

(iv) Quick Start Generation Resources (QSGRs);

(d) Ancillary Service Resource Responsibility for ECRS from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources; and

(iii) Controllable Load Resources; and

(iv) QSGRs;

(e) ECRS deployed to Generation and Load Resources;

(f) Non-Spin available from:

(i) On-Line Generation Resources with Energy Offer Curves;

(ii) Undeployed Load Resources;

(iii) Off-Line Generation Resources; and

(iv) Resources with Output Schedules;

(g) Ancillary Service Resource Responsibility for Non-Spin from:

(i) On-Line Generation Resources with Energy Offer Curves;

(ii) On-Line Generation Resources with Output Schedules;

(iii) Load Resources;

(iv) Off-Line Generation Resources excluding QSGRs; and

(v) QSGRs;

(h) Undeployed Reg-Up and Reg-Down;

(i) Ancillary Service Resource Responsibility for Reg-Up and Reg-Down;

(j) Deployed Reg-Up and Reg-Down;

(k) Available capacity:

(i) With Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;

(ii) With Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;

(iii) Without Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;

(iv) Without Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;

(v) With RTM Energy Bid curves from available Controllable Load Resources in the ERCOT System that can be used to decrease Base Points (energy consumption) in SCED;

(vi) With RTM Energy Bid curves from available Controllable Load Resources in the ERCOT System that can be used to increase Base Points (energy consumption) in SCED;

(vii) From Resources participating in SCED plus the Reg-Up, ECRS, and RRS from Load Resources and the Net Power Consumption minus the Low Power Consumption from Load Resources with a validated Real-Time RRS and ECRS Schedule;

(viii) From Resources included in item (vii) above plus reserves from Resources that could be made available to SCED in 30 minutes;

(ix) In the ERCOT System that can be used to increase Generation Resource Base Points in the next five minutes in SCED; and

(x) In the ERCOT System that can be used to decrease Generation Resource Base Points in the next five minutes in SCED;

(l) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of EMR;

(m) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of OUT;

(n) Aggregate net telemetered consumption for Resources with a telemetered Resource Status of OUTL; and

(o) The ERCOT-wide PRC calculated as follows:

$$PRC_1 = \sum_{i=\text{online generation resource}}^{\text{All online generation resources}} \text{Min}(\text{Max}((\text{RDF}*(\text{HSL-NFRC}) - \text{Actual Net Telemetered Output})_i, 0.0), 0.2*\text{RDF}*(\text{HSL-NFRC})_i),$$

where the included On-Line Generation Resources do not include WGRs, nuclear Generation Resources, or Generation Resources with an output less than or equal to 95% of telemetered LSL or with a telemetered status of ONTEST, ONHOLD, STARTUP, or SHUTDOWN.

$$PRC_2 = \sum_{i=\text{online WGR}}^{\text{All online WGRs}} \text{Min(Max((RDF}_W\text{*HSL – Actual Net Telemetered Output)}_i\text{ , 0.0) , 0.2*RDF}_W\text{*HSL}_i\text{)},$$

where the included On-Line WGRs only include WGRs that are Primary Frequency Response-capable.

$$PRC_3 = \sum_{i=\text{online generation resource}}^{\text{All online generation resources}} \text{((Synchronous condenser output)}_i\text{ as qualified by item (8) of Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve and ERCOT Contingency Reserve Service Providers))}$$

$$PRC_4 = \sum_{i=\text{online load resource}}^{\text{All online load resources}} \text{(Min(Max((Actual Net Telemetered Consumption – LPC), 0.0), ECRS and RRS Ancillary Service Resource Responsibility * 1.5) from all Load Resources controlled by high-set under frequency relays carrying an ECRS and/or RRS Ancillary Service Resource Responsibility)}_i$$

$$PRC_5 = \sum_{i=\text{online load resource}}^{\text{All online load resources}} \text{Min(Max((LRDF\_1*Actual Net Telemetered Consumption – LPC)}_i\text{, 0.0), (0.2 * LRDF\_1 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED and } \underline{\text{qualified for Regulation Service and/or RRS and}} \text{ carrying Ancillary Service Resource Responsibility}$$

$$PRC_6 = \sum_{i=\text{online load resource}}^{\text{All online load resources}}$$

Min(Max((LRDF_2 * Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_2 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED and qualified for Regulation Service and/or RRS and not carrying Ancillary Service Resource Responsibility

$$PRC_7 = \sum_{i=\text{online FFR resource}}^{\text{All online FFR resources}}$$

(Capacity from Resources capable of providing FFR)$_i$

$$PRC_8 = \sum_{i=\text{online ESR}}^{\text{All online ESR}}$$

(If discharging or idle, Min(X% of HSL based on droop, HSL-ESR-Gen "injection", the capacity that can be sustained for 15 minutes per the State of Charge), else Min(X% of (HSL – LSL(ESR "charging") based on droop, the capacity that can be sustained for 15 minutes per the State of Charge – LSL(ESR "charging")))

Excludes ESR capacity used to provide FFR

$PRC = PRC_1 + PRC_2 + PRC_3 + PRC_4 + PRC_5 + PRC_6 + PRC_7 + PRC_8$

The above variables are defined as follows:

Variable	**Unit**	**Description**
PRC_1	MW	Generation On-Line greater than 0 MW
PRC_2	MW	WGRs On-Line greater than 0 MW
PRC_3	MW	Synchronous condenser output
PRC_4	MW	Capacity from Load Resources carrying ECRS Ancillary Service Resource Responsibility
PRC_5	MW	Capacity from Controllable Load Resources active in SCED and qualified for Regulation Service and/or RRS and carrying Ancillary Service Resource Responsibility
PRC_6	MW	Capacity from Controllable Load Resources active in SCED and qualified for Regulation Service and/or RRS and not carrying Ancillary Service Resource Responsibility
PRC_7	MW	Capacity from Resources capable of providing FFR
PRC_8	MW	ESR capacity capable of providing Primary Frequency Response
PRC	MW	Physical Responsive Capability
X	Percentage	Percent threshold based on the Governor droop setting of ESRs

RDF		The currently approved Reserve Discount Factor
RDF_W		The currently approved Reserve Discount Factor for WGRs
LRDF_1		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources carrying Ancillary Service Resource Responsibility
LRDF_2		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources not carrying Ancillary Service Resource Responsibility
NFRC	MW	Non-Frequency Responsive Capacity

(2) Each QSE shall operate Resources providing Ancillary Service capacity to meet its obligations. If a QSE experiences temporary conditions where its total obligation for providing Ancillary Service cannot be met on the QSE's Resources, then the QSE may add additional capability from other Resources that it represents. It adds that capability by changing the Resource Status and updating the Ancillary Service Schedules and Ancillary Services Resource Responsibility of the affected Resources and notifying ERCOT under Section 6.4.9.1, Evaluation and Maintenance of Ancillary Service Capacity Sufficiency. If the QSE is unable to meet its total obligations to provide committed Ancillary Services capacity, the QSE shall notify ERCOT immediately of the expected duration of the QSE's inability to meet its obligations. ERCOT shall determine whether replacement Ancillary Services will be procured to account for the QSE's shortfall according to Section 6.4.9.1.

(3) The Load Resource Reserve Discount Factors (RDFs) for Controllable Load Resources (LRDF_1 and LRDF_2) shall be subject to review and approval by TAC.

(4) The RDFs used in the PRC calculation shall be posted to the ERCOT website no later than three Business Days after approval.

[NPRR1010, NPRR1014, NPRR1029, and NPRR1204: Replace applicable portions of Section 6.5.7.5 above with the following upon system implementation for NPRR1014 or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1204:]

6.5.7.5 Ancillary Services Capacity Monitor

(1) Every ten seconds, ERCOT shall calculate the following and provide Real-Time summaries to ERCOT Operators and all Market Participants using ICCP and postings on the ERCOT website showing the Real-Time total system amount of:

(a) RRS capability from:

(i) Generation Resources and ESRs in the form of PFR that can be sustained for the SCED duration requirements of PFR;

(ii) Load Resources, excluding Controllable Load Resources, capable of responding via under-frequency relay;

(iii) Controllable Load Resources in the form of PFR;

(iv) Resources, other than ESRs, capable of Fast Frequency Response (FFR); and

(v) ESRs, in the form of FFR, that can be sustained for the SCED duration requirements of FFR;(b) Ancillary Service Resource awards for RRS to:

(i) Generation Resources and ESRs in the form of PFR;

(ii) Load Resources, excluding Controllable Load Resources, capable of responding by under-frequency relay;

(iii) Controllable Load Resources in the form of PFR; and

(iv) Resources providing FFR;

(c) ECRS capability from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources;

(iv) Quick Start Generation Resources (QSGRs); and

(v) ESRs that can be sustained for the SCED duration requirements of ECRS.

(d) Ancillary Service Resource awards for ECRS to:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources; and

(iii) Controllable Load Resources;

(iv) QSGRs; and

(v) ESRs.

(e) ECRS manually deployed by Resources with a Resource Status of ONSC;

(f) Non-Spin available from:

(i) On-Line Generation Resources with Energy Offer Curves;

(ii) Undeployed Load Resources;

(iii) Off-Line Generation Resources and On-Line Generation Resources with power augmentation;

(iv) Resources with Output Schedules; and

(v) ESRs that can be sustained for the SCED duration requirements of Non-Spin.

(g) Ancillary Service Resource awards for Non-Spin to:

(i) On-Line Generation Resources with Energy Offer Curves;

(ii) On-Line Generation Resources with Output Schedules;

(iii) Load Resources;

(iv) Off-Line Generation Resources excluding Quick Start Generation Resources (QSGRs), including Non-Spin awards on power augmentation capacity that is not active on On-Line Generation Resources;

(v) QSGRs; and

(vi) ESRs.

(h) Reg-Up and Reg-Down capability (for ESRs, the SCED duration requirements of Reg-Up and Reg-Down are considered);

(i) Undeployed Reg-Up and Reg-Down;

(j) Ancillary Service Resource awards for Reg-Up and Reg-Down;

(k) Deployed Reg-Up and Reg-Down;

(l) Available capacity:

(i) With Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;

(ii) With Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;

(iii) Without Energy Offer Curves in the ERCOT System that can be used to increase Generation Resource Base Points in SCED;

(iv) Without Energy Offer Curves in the ERCOT System that can be used to decrease Generation Resource Base Points in SCED;

(v) With RTM Energy Bid curves from available Controllable Load Resources in the ERCOT System that can be used to decrease Base Points (energy consumption) in SCED;

(vi) With RTM Energy Bid curves from available Controllable Load Resources in the ERCOT System that can be used to increase Base Points (energy consumption) in SCED;

(vii) From Resources participating in SCED plus the Reg-Up, RRS, and ECRS from Load Resources and the Net Power Consumption minus the Low Power Consumption from Load Resources with a validated Real-Time RRS and ECRS awards;

(viii) With Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to increase ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;

(ix) With Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to decrease ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;

(x) Without Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to increase ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;

(xi) Without Energy Bid/Offer Curves for ESRs in the ERCOT System that can be used to decrease ESR Base Points in SCED while respecting SCED duration requirements for ESR Base Points in SCED;

(xii) From Resources included in item (vii) above plus reserves from Resources that could be made available to SCED in 30 minutes;

(xiii) In the ERCOT System that can be used to increase Generation Resource Base Points in the next five minutes in SCED; and

(xiv) In the ERCOT System that can be used to decrease Generation Resource Base Points in the next five minutes in SCED;

(xv) The total capability of Resources available to provide the following combinations of Ancillary Services, based on the Resource telemetry from the QSE and capped by the limits of the Resource:

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

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

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

(m) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of EMR;

(n) Aggregate telemetered HSL capacity for Resources with a telemetered Resource Status of OUT;

(o) Aggregate net telemetered consumption for Resources with a telemetered Resource Status of OUTL; and

(p) The ERCOT-wide PRC calculated as follows:

$$PRC_1 = \sum_{\substack{i=\text{online generation resource}}}^{\text{All online generation resources}} \mathbf{Min(Max((RDF*FRCHL - FRCO)_i\ ,\ 0.0)\ ,\ 0.2*RDF*FRCHL_i),}$$

where the included On-Line Generation Resources do not include WGRs, nuclear Generation Resources, or Generation Resources with an output less than or equal to 95% of telemetered LSL with a telemetered status of ONTEST, ONHOLD, STARTUP, or SHUTDOWN.

$$PRC_2 = \sum_{\substack{i=\text{online WGR}}}^{\text{All online WGRs}} \mathbf{Min(Max((RDF_W*HSL - Actual\ Net\ Telemetered\ Output)_i\ ,\ 0.0)\ ,\ 0.2*RDF_W*HSL_i),}$$

where the included On-Line WGRs only include WGRs that are Primary Frequency Response-capable.

$$PRC_3 = \sum_{\substack{i=\text{online generation resource}}}^{\text{All online generation resources}} \mathbf{((Synchronous\ condenser\ output)_i\ as\ qualified\ by\ item\ (8)\ of\ Operating\ Guide\ Section\ 2.3.1.2,\ Additional\ Operational\ Details\ for\ Responsive\ Reserve\ and\ ERCOT\ Contingency\ Reserve\ Service\ Providers))}$$

$PRC_4 = \sum_{i=\text{online load resource}}^{\text{All online load resources}}$	(Min(Max((Actual Net Telemetered Consumption – LPC), 0.0), ECRS and RRS Ancillary Service Resource award * 1.5) from all Load Resources controlled by high-set under-frequency relays with an ECRS and/or RRS Ancillary Service Resource award)$_i$
$PRC_5 = \sum_{i=\text{online load resource}}^{\text{All online load resources}}$	Min(Max((LRDF_1*Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_1 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED <u>and qualified for Regulation Service and/or RRS</u> with an Ancillary Service Resource award
$PRC_6 = \sum_{i=\text{online load resource}}^{\text{All online load resources}}$	Min(Max((LRDF_2 * Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_2 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED <u>and qualified for Regulation Service and/or RRS</u> without an Ancillary Service Resource award
$PRC_7 = \sum_{i=\text{online FFR resource}}^{\text{All online FFR resources}}$	(Capacity from Resources capable of providing FFR)$_i$
$PRC_8 = \sum_{i=\text{online ESR}}^{\text{All online ESR}}$	(If discharging or idle, Min(X% of HSL based on droop, HSL-ESR-Gen "injection", the capacity that can be sustained for 15 minutes per the State of Charge), else Min(X% of (HSL – LSL(ESR "charging") based on droop, the

capacity that can be sustained for 15 minutes per the State of Charge – LSL(ESR "charging")))

Excludes ESR capacity used to provide FFR

$$PRC_9 = \sum_{\substack{i=online\\ESR}}^{\substack{All\\online\\DC\text{-}Coupled\\Resources}}$$ **(If discharging or idle, Min(X% of HSL based on droop, HSL-Gen "injection", the sum of the MW headroom available from the intermittent renewable generation component and the MW capacity that can be sustained for 15 minutes per the ESS State of Charge), else Min(X% of Real-Time Total Capacity based on droop, the sum of the MW headroom available from the intermittent renewable generation component and the MW capacity that can be sustained for 15 minutes per the ESS State of Charge))**

Excludes DC-Coupled Resource capacity used to provide FFR

$$PRC = PRC_1 + PRC_2 + PRC_3 + PRC_4 + PRC_5 + PRC_6 + PRC_7 + PRC_8 + PRC_9$$

The above variables are defined as follows:

Variable	Unit	Description
PRC_1	MW	Generation On-Line greater than 0 MW
PRC_2	MW	WGRs On-Line greater than 0 MW
PRC_3	MW	Synchronous condenser output
PRC_4	MW	Capacity from Load Resources with an ECRS Ancillary Service Resource award
PRC_5	MW	Capacity from Controllable Load Resources active in SCED <u>and qualified for Regulation Service and/or RRS</u> with an Ancillary Service Resource award
PRC_6	MW	Capacity from Controllable Load Resources active in SCED <u>and qualified for Regulation Service and/or RRS</u> without an Ancillary Service Resource award
PRC_7	MW	Capacity from Resources capable of providing FFR
PRC_8	MW	ESR capacity capable of providing Primary Frequency Response
PRC_9	MW	Capacity from DC-Coupled Resources capable of providing Primary Frequency Response
PRC	MW	Physical Responsive Capability
X	Percentage	Percent threshold based on the Governor droop setting of ESRs
RDF		The currently approved Reserve Discount Factor
RDF_W		The currently approved Reserve Discount Factor for WGRs

LRDF_1		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources awarded an Ancillary Service Resource award
LRDF_2		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources not awarded an Ancillary Service Resource award
FRCHL	MW	Telemetered High limit of the FRC for the Resource
FRCO	MW	Telemetered output of FRC portion of the Resource

(2) The Load Resource Reserve Discount Factors (RDFs) for Controllable Load Resources (LRDF_1 and LRDF_2) shall be subject to review and approval by TAC.

(3) The RDFs used in the PRC calculation shall be posted to the ERCOT website no later than three Business Days after approval.

(4) ERCOT shall display on the ERCOT website and update every ten seconds a rolling view of the ERCOT-wide PRC, as defined in paragraph (1)(p) above, for the current Operating Day.

8.5.2.1 ERCOT Required Primary Frequency Response

(1) All Generation Resources, ESRs, Controllable Load Resources that are capable of providing Primary Frequency Response, SOTGs, and SOTSGs~~, and Controllable Load Resources~~ shall provide Primary Frequency Response in accordance with the requirements established in the Operating Guides.

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

(1) All Generation Resources, ESRs, Controllable Load Resources that are capable of providing Primary Frequency Response, SOTGs, SOTSGs, and SOTESSs~~, and Controllable Load Resources~~ shall provide Primary Frequency Response in accordance with the requirements established in the Operating Guides.

(2) ERCOT shall evaluate, with the assistance of the appropriate TAC subcommittee, Primary Frequency Response during FMEs. The actual Generation Resource or ESR response must be compiled to determine if adequate Primary Frequency Response was provided.

(3) ERCOT and the appropriate TAC subcommittee shall review each FME, verifying the accuracy of data. Data that is in question may be requested from the QSE for comparison or individual Generation Resource or ESR data may be retrieved from ERCOT's database.

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[NPRR963: Replace paragraph (3) above with the following upon system implementation:]

(3) ERCOT and the appropriate TAC subcommittee shall review each FME, verifying the accuracy of data. Data that is in question may be requested from the QSE for comparison or individual Resource data may be retrieved from ERCOT's database.

Revised ERCOT Impact Analysis Report

NPRR Number	1244	NPRR Title	**Clarification of Controllable Load Resource Primary Frequency Response Responsibilities**
Impact Analysis Date		September 13, 2024	
Estimated Cost/Budgetary Impact		Between $70k and $100k	
Estimated Time Requirements		The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 5 to 7 months	
ERCOT Staffing Impacts (across all areas)		Implementation Labor: 100% ERCOT; 0% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Net Dependable Capability and Reactive Capability 50% • Energy Management System 50%	
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.

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NOGRR Number	262	NOGRR Title	Provisions for Operator-Controlled Manual Load Shed
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	First of the month following Public Utility Commission of Texas (PUCT) approval.		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	2.6.1, Automatic Firm Load Shedding 4.5.3, Implementation 4.5.3.4, Load Shed Obligation 8L, Emergency Operations Plan		
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1221, Related to NOGRR262, Provisions for Operator-Controlled Manual Load Shed Nodal Operating Guide Section 4.5.3.3, EEA Levels		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) aligns provisions regarding manual and automatic firm Load shed and clarifies the proper use and interplay of Under-Voltage Load Shed (UVLS), Under-Frequency Load Shed (UFLS), and manual Load shed.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ General system and/or process improvement(s)		

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	☒ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	North American Electric Reliability Corporation (NERC) Reliability Standards EOP-011-3, Emergency Operations, and EOP-011-4, Emergency Operations, require ERCOT, as a NERC-registered balancing authority, to develop, maintain, and implement operating plan(s) to mitigate capacity emergencies and energy emergencies within its balancing authority area. This NOGRR addresses the requirements in EOP-011-3 and EOP-011-4 that the plan(s) must include provisions for Transmission Operators (TOs) to implement operator-controlled manual Load shed during an emergency that accounts for 1) provisions for manual Load shed capable of being implemented in a timeframe adequate for mitigating the emergency; 2) provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; 3) provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS; and 4) provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions. This NOGRR ensures the required alignment between ERCOT and TOs during an Energy Emergency Alert (EEA) Level 3 Load shed event and ensures ERCOT and TOs understand their respective responsibilities during an EEA Level 3 firm Load shed event. Once ERCOT issues an operating instruction to shed Load, it is crucial to the reliability of the ERCOT System that Load shed be implemented consistent with the expectations of the ERCOT System operators. These revisions require TOs, Transmission Service Providers (TSPs), and Distribution Service Providers (DSPs), to manually shed firm Load without delay and within a defined timeframe to mitigate an actual emergency. ERCOT plans to continue to conduct the annual winter Load shed survey to obtain each TSP's most up-to-date firm Load shed capability. This NOGRR also includes provisions requiring TOs to coordinate with Transmission and/or Distribution Service Providers (TDSPs) to minimize overlap of any critical loads with designated manual firm Load shed circuits and minimize overlap of UFLS/UVLS circuits with designated manual firm Load shed circuits. ERCOT will consider further provisions in the future to address the staggered timeframes within EOP-011-4 that identify and prioritize designated critical

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	natural gas infrastructure loads that are essential to the reliability of the ERCOT System and minimize overlapping of automatic firm Load shed and manual firm Load shed with identified critical loads that are essential to the reliable operation of the ERCOT System. Pursuant to paragraph (6) of Section 1.3.1, Introduction, an Alignment NOGRR for Section 4.5.3.3, EEA Levels, will be published within five Business Days of the ERCOT Board recommending approval of NPRR1221.
ROS Decision	On 4/4/24, ROS voted unanimously to table NOGRR262 and refer the issue to the Operations Working Group (OWG). All Market Segments participated in the vote. On 7/11/24, ROS voted unanimously to recommend approval of NOGRR262 as amended by the 6/27/24 OWG comments. All Market Segments participated in the vote. On 8/1/24, ROS voted to endorse and forward to TAC the 7/11/24 ROS Report and 3/20/24 Impact Analysis. All Market Segments participated in the vote.
Summary of ROS Discussion	On 4/4/24, ERCOT Staff presented NOGRR262. Participants requested further review of NOGRR262 and the related NPRR1221 by OWG. On 7/11/24, participants reviewed the 6/27/24 OWG comments. On 8/1/24, participants reviewed the 3/20/24 Impact Analysis.
TAC Decision	On 8/28/24, TAC voted unanimously to recommended approval of NOGRR262 as recommended by ROS in the 8/1/24 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/28/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)

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Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NOGRR262 as recommended by TAC in the 8/28/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR262.
ERCOT Opinion	ERCOT supports approval of NOGRR262.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR262 and believes it provides a positive market impact by ensuring the required alignment between ERCOT and TOs during an Energy Emergency Alert (EEA) Level 3 Load shed event, and ensuring ERCOT and TOs understand their respective responsibilities during an EEA Level 3 firm Load shed event.

Sponsor	
Name	Shun Hsien (Fred) Huang
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Company	ERCOT
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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**

CEHE 041724	Specified that 25% of ERCOT System Load shall be equipped with provisions for automatic UFLS unless provisions in Section 4.5.3.3 are required to meet ERCOT operating instructions for manual Load shed; clarified that Supervisory Control and Data Acquisition (SCADA)-controlled Load shed methods are preferred, and that not all TOs/ TDSPs possess non-SCADA-controlled Load shed methods; and clarified that whenever possible, the TO/TDSP shall restore SCADA-controlled Load by replacing it with non-SCADA-controlled Load when appropriate
AEP 041724	Added language to distinguish TO-affiliated controlled SCADA from entities that would be allocated a Load shed share and thus not require the TO to shed extra SCADA-controlled Load to make up for TO non-directly-affiliated Loads such as non-critical industrial Loads or third party TDSPs
Oncor 051324	Proposed clarifications and added a requirement to for the TO to notify ERCOT if its SCADA-controlled Load shed capability has been exhausted
GSEC 053024	Added the phrase "by the TO and/or TDSP(s)" to address the situation where several of GSEC's individual member TDSP cooperatives do not have SCADA control for Load shed.
OWG 062724	Reflected discussions at the June 20, 2024 OWG meeting

Market Rules Notes

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

- NOGRR265, Related to NPRR1238, Voluntary Registration of Loads with Curtailable Load Capabilities
  - Section 4.5.3.4
- NOGRR268, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era
  - Section 4.5.3

Proposed Guide Language Revision

2.6.1 Automatic Firm Load Shedding

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph, unless provisions specified in Section 4.5.3.3, EEA Levels, are required to meet ERCOT operating instructions for manual Load shed. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required

percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, below. TOs may, but are not required to, provide supplemental anti-stall under-frequency Load relief in the amounts described in Table 2, Supplemental Anti-Stall UFLS Stages, below. If the TOs provide supplemental anti-stall under-frequency Load relief, the under-frequency relays shall be set to use the frequency thresholds and time delays described in Table 2. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

[NOGRR226: Replace paragraph (1) above with the following upon system implementation but no earlier than October 1, 2026:]

(1) At least 25% of the ERCOT System Load shall be equipped at all times with provisions for automatic Under-Frequency Load Shedding (UFLS) as described in this paragraph, unless provisions specified in Section 4.5.3.3, EEA Levels, are required to meet ERCOT operating instructions for manual Load shed. In the event of an under-frequency event, each Transmission Operator (TO) shall provide Load relief by shedding the required percentage of its Distribution Service Provider (DSP)-connected Load and transmission-level Customer Load using automatic under-frequency relays, as specified in Table 1, Standard UFLS Stages, and Table 2, Supplemental/Anti-Stall UFLS Stages, below. For the purposes of this paragraph, the TO Load will be the amount of Load being served by the DSPs that the TO represents, as well as the TO's transmission-level Customer Load, when the ERCOT frequency drops to the 59.5 Hz threshold. As such, TO Load that has already been removed from the system without restoration prior to the 59.5 Hz frequency threshold will not apply to meeting TO Load relief percentage requirements as stated in Table 1 and Table 2 below.

Table 1: Standard UFLS Stages

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	No more than 30 cycles
59.1 Hz	A total of at least 5% of the TO Load	No more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.7 Hz	A total of at least 15% of the TO Load	No more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	No more than 30 cycles

[NOGRR247: Replace Table 1 above with the following upon system implementation but no earlier than October 1, 2026:]

Frequency Threshold	TO Load Relief	Delay to Trip
59.3 Hz	At least 5% of the TO Load	At least six cycles but no more than 30 cycles
59.1 Hz	A total of at least 10% of the TO Load	At least six cycles but no more than 30 cycles
58.9 Hz	A total of at least 15% of the TO Load	At least six cycles but no more than 30 cycles
58.7 Hz	A total of at least 20% of the TO Load	At least six cycles but no more than 30 cycles
58.5 Hz	A total of at least 25% of the TO Load	At least six cycles but no more than 30 cycles

Table 2: Supplemental/Anti-Stall UFLS Stages

Frequency Threshold	TO Load Relief	Delay to Trip
59.5 Hz	At least 1.5% of the TO Load	90 seconds
59.5 Hz	A total of at least 3.0% of the TO Load	120 seconds
59.5 Hz	A total of at least 4.5% of the TO Load	150 seconds

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

with this annual survey does not excuse the TO from compliance with the requirements of paragraph (1) above in an actual frequency event. To assist TOs, ERCOT will provide the TO's inventory, including substation and capacity amounts, of registered Load Resources in its area within ten Business Days of receiving a request in writing from a TO.

(3) A TO may meet the Load relief requirements of the Supplemental anti-stall UFLS stages by utilizing Load that would otherwise be utilized to meet the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages. In this circumstance, the TO's Load relief responsibility at the 59.1 Hz, 58.9 Hz, 58.7 Hz, and 58.5 Hz standard UFLS stages is reduced by the amount of Load already shed in the supplemental anti-stall UFLS stages. A TO may not meet the Load relief requirements of the supplemental anti-stall UFLS stages by utilizing Load that the TO needs to meet the 59.3 Hz standard UFLS stages.

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

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall ensure that Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs) are connected to circuits that are not subject to disconnection during UFLS events, except as permitted by Protocol Section 3.8.6, Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs). DSPs shall ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

[NOGRR250: Replace paragraph (5) above with the following upon system implementation of NPRR1171:]

(5) DSPs shall ensure, to the extent possible, and under the direction of ERCOT, that Loads equipped with under-frequency relays are dispersed geographically throughout the ERCOT Region to minimize the impact of Load shedding within a given geographical area. Customers equipped with under-frequency relays shall be dispersed without regard to which Load Serving Entity (LSE) serves the customer. DSPs shall

ensure that the under-frequency relays connected to each Load will operate with a fixed time delay as specified in paragraph (1) above. Total time from the time when a sustained under-frequency condition first reaches one of the values specified above to the time Load is interrupted shall be no more than the maximum fixed time delay specified in paragraph (1) above plus 10 cycles, including all relay and breaker operating times, and no less than any applicable minimum fixed time delay specified in paragraph (1) above. If the frequency drops below 58.5 Hz, ERCOT shall determine additional steps to continue operation.

(6) If a loss of Load occurs due to the operation of under-frequency relays, a DSP or its designee may rotate the physical Load interrupted to minimize the duration of interruption experienced by individual Customers or to restore the availability of under-frequency Load-shedding capability. In no event shall the initial total amount of Load without service be decreased without the approval of ERCOT. TOs, in coordination with DSPs, shall make every reasonable attempt to restore Load, either by automatic or manual means, to preserve system integrity. Restoration of any Load shed by UFLS systems, including supplemental anti-stall UFLS Load, shall be coordinated with ERCOT by the TO. In the event frequency drops below any of the frequency thresholds specified in the tables in paragraph (1) above, and a TO's UFLS relays that previously activated as a result of reaching that same frequency threshold have not been restored since the previous excursion, the Load on the feeders controlled by those relays shall be counted toward the TO's satisfaction of the percentages in paragraph (1) above for that subsequent frequency excursion.

4.5.3 Implementation

Commented [BA1]: Please note NOGRR268 also proposes revisions to this section.

(1) ERCOT shall be responsible for monitoring system conditions, initiating the EEA levels below, notifying all Qualified Scheduling Entities (QSEs) representing Resources and Transmission Operators (TOs), and coordinating the implementation of the EEA conditions while maintaining transmission security limits. QSEs and TOs will notify all the Market Participants they represent of each declared EEA level.

(2) During the EEA, ERCOT has the authority to obtain energy from non-ERCOT Control Areas using Direct Current Tie(s) (DC Tie(s)) or by using Block Load Transfers (BLTs) to move load to non-ERCOT Control Areas. ERCOT maintains the authority to curtail energy schedules flowing into or out of the ERCOT System across the DC Ties in accordance with North American Electric Reliability Corporation (NERC) scheduling guidelines.

(3) ERCOT, at management's discretion, may at any time issue an ERCOT-wide appeal through the public news media for voluntary energy conservation.

(4) There may be insufficient time to implement all levels in sequence. ERCOT may immediately implement EEA Level 2 when clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT may immediately implement Level

3 of the EEA any time the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz for any duration of time. ERCOT shall immediately implement Level 3 any time the steady-state frequency is below 59.5 Hz for any duration.

(5) Percentages for Level 3 Load shed will be based on the previous year's TSP peak Loads, as reported to ERCOT, and will be reviewed by ERCOT and modified annually.

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs and TSPs. QSEs and TSPs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

[NOGRR177: Replace paragraph (6) above with the following upon system implementation of NPRR857:]

(6) The ERCOT System Operator shall declare the EEA levels to be taken by QSEs, TSPs, and DCTOs. QSEs, TSPs, and DCTOs shall implement actions under that level (and all above if not previously accomplished) and if ordered by the ERCOT shift supervisor or his designate, shall report back to the ERCOT System Operator when the requested level has been completed.

(7) During EEA Level 3, ERCOT must be capable of manually shedding sufficient firm Load to arrest frequency decay and to prevent generator tripping. The amount of manual firm Load to be shed may vary depending on ERCOT Transmission Grid conditions during the event. Each TSP will be capable of manually shedding its allocation of firm Load, without delay~~, avoiding whenever possible the use of Load designated as critical or for Under-Frequency Load Shed (UFLS)/ Under-Voltage Load Shed (UVLS)~~. The maximum time for the TSP to interrupt firm Load will depend on how much Load is to be shed and whether the Load is to be interrupted by Supervisory Control and Data Acquisition (SCADA) or ~~by the dispatch of personnel to substations~~ other, non-SCADA-controlled methods. Since the need for firm Load shed is immediate, interruption by SCADA is preferred. Each TO, TSP, and Transmission and/or Distribution Service Provider (TDSP) and their designated agents will comply with ~~T~~the following requirements ~~apply for~~ when implementing an ERCOT instruction to shed firm Load:

(a) Load interrupted manually by SCADA will be shed without delay upon receipt of a Load shed instruction and in a time period not to exceed 30 minutes after receipt of the Load shed instruction for each Entity's portion of every Load shed instruction. SCADA-controlled Load shed ~~should~~is preferred to be utilized by the TO and/or TDSP(s) before non-SCADA controlled Load shed when executing a Load shed instruction;

(b) ~~Load interrupted by dispatch of personnel to substations to manually shed Load will be implemented within a time period not to exceed one hour.~~If sufficient amounts of SCADA-controlled Load are not available to fulfill an Entity's~~fully execute a~~ manual Load shed instruction, the TO and/or TDSP(s) shall complete, if applicable~~possible~~, the remaining manual Load shed through non-SCADA-controlled Load shed methods without delay upon receipt of a Load shed instruction and in a time period not to exceed one hour after receipt of the Load shed instruction. A TO shall notify ERCOT if its SCADA-controlled Load shed capabilities have been exhausted; and

(c) ~~After Load is interrupted as described in paragraphs (a) and (b) above,~~ If determined appropriate by the TO and as soon as practicable~~Whenever possible~~, ~~each~~the TO and/or TDSP(s) ~~should assess its remaining~~ should ~~shall~~ restore SCADA-controlled Load ~~shed capabilities and, if appropriate and as soon as practicable, shed Load available for manual~~by shedding ~~using~~ non-SCADA-controlled Load ~~shed while simultaneously restoring service to an equivalent amount of previously interrupted~~not shed in paragraph (b) above~~, when appropriate~~, in an effort to make SCADA-controlled Load ~~as a means of maintaining its portion of SCADA-controlled Load~~ available for a potential subsequent Load shed instruction~~next event~~~~Load shed~~.

~~(e) The initial clock on the firm Load shed shall apply only to Load shed amounts up to 1000 MW total. Load shed amount requests exceeding 1000 MW on the initial clock may take longer to implement; and~~

~~(d) If, after the first Load shed instruction, ERCOT determines that an additional amount of firm Load should be shed, another clock will begin anew. The time frames mentioned above will apply.~~

(8) Each TSP, or its designated agent, will provide ERCOT a status report of Load shed progress within 30 minutes of the time of ERCOT's instruction or upon ERCOT's request.

(9) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(a) of Section 4.5.3.1, General Procedures Prior to EEA Operations, ERCOT may control the post-contingency flow to within the 15-Minute Rating in Security-Constrained Economic Dispatch (SCED). After Physical Responsive Capability (PRC) is restored to at least 3,000 MW or the Emergency Condition has ended, whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low, ERCOT shall restore control to the post-contingency flow to within the Emergency Rating for these constraints that utilized the 15-Minute Rating in SCED.

(10) During EEA Level 2 or 3, for those constraints that meet the criteria identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT shall continue to enforce constraints associated with double-circuit contingencies throughout an EEA if the double-circuit failures are determined to be at high risk of occurring, due to system conditions. For all other double-circuit contingencies identified in paragraph (3)(b) of Section 4.5.3.1, ERCOT will enforce only the associated single-circuit contingencies during EEA Level 2 or 3. ERCOT shall resume enforcing such constraints as a double-circuit contingency after PRC is restored to at least 3,000 MW or the Emergency Condition has ended,

whichever is later, and ERCOT has determined that system conditions have improved such that the chance of re-entering into an EEA Level 2 or 3 is low. For constraints related to stability limits that are not IROLs, ERCOT may elect not to enforce double-circuit contingencies during EEA Level 3 only.

4.5.3.4 Load Shed Obligation

Commented [BA2]: Please note NOGRR265 also proposes revisions to this section.

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

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

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

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

(3) The summer Load shed table will be used during a hot weather Load shed event and the winter Load shed table will be used during a cold weather Load shed event. ERCOT will determine, in its sole discretion, whether an EEA event will be treated as a hot weather or cold weather Load shed event based on the weather conditions. The summer and winter Load shed time periods will be published annually with the updated obligation tables in paragraph (2) above. In addition, if ERCOT issues an Operating Condition Notice (OCN), it will notify Market Participants which Load shed table would apply to the potential Load shed event. When ERCOT directs TOs to shed Load, it will specify which Load shed table applies for the Load shed event. ERCOT shall use the same Load shed table for the duration of a Load shed event.

(4) ERCOT shall maintain the Seasonal Load shed tables reflecting each TO's total Load shed obligation on the ERCOT website. The Load shed obligation percentages will be

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

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

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

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

ERCOT Nodal Operating Guides
Section 8
Attachment L

Emergency Operations Plan

~~November 1, 2023~~TBD

Board Report

This attachment provides a template to be used by each Transmission Operator (TO) for the development of its emergency operations plan to mitigate operating emergencies, as required by the applicable North American Electric Reliability Corporation (NERC) Reliability Standard. The emergency operations plan can be made up of multiple parts and does not need to be a single document. When multiple parts are used, the TO shall include documentation describing the location of each element required by the applicable NERC Reliability Standard. Each plan should include each of the elements listed below:

I. PURPOSE – The purpose statement will address the TO's operations plan to mitigate operating emergencies.

II. SCOPE – The scope statement shall provide, in a brief summary, the boundaries of the emergency operations plan and to whom the emergency operations plan applies.

III. DEFINITIONS – Definitions of terms that are used in the TO emergency operations plan that are not common to the ERCOT Region. Define what is considered an operating emergency.

IV. KEY PERSONNEL ROLES AND RESPONSIBILITIES – Identify roles and responsibilities of key personnel that are responsible for activating the plan.

V. PROCESSES TO PREPARE FOR AND MITIGATE EMERGENCIES – Include the following:

A. Notification to ERCOT to include current and known projected Real-Time conditions, when experiencing an operating emergency;

B. Cancellation of Transmission Facility Outages;

C. Transmission system reconfiguration;

D. ~~Provisions for o~~Operator-controlled manual Load shed during an Emergency Condition that accounts for each of the following:

1. Provisions for manual Load shed ~~that minimizes the overlap with automatic Load shedding and that is~~ capable of being implemented in a timeframe adequate for mitigating the emergency; ~~and~~

2. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads;

3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for Under-Frequency Load Shed (UFLS) or Under-Voltage Load Shed (UVLS); and

4. Provisions to limit the utilization of UFLS or UVLS circuits for manual Load shed to situations where such use is consistent with the ERCOT Nodal Protocols and ERCOT Nodal Operating Guide and is warranted by system conditions.

E. Provisions to determine reliability impacts of:

1. cold weather conditions; and

2. extreme weather conditions.

ERCOT Impact Analysis Report

NOGRR Number	262	NOGRR Title	Provisions for Operator-Controlled Manual Load Shed
Impact Analysis Date	March 20, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NOGRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NOGRR Number	**263**	**NOGRR Title**	**Related to NPRR1244, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities**
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1244, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities		
Priority and Rank Assigned	Not applicable		
Nodal Operating Guide Sections Requiring Revision	2.2.8, Performance/Disturbance/Compliance Analysis 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response		
Related Documents Requiring Revision/Related Revision Requests	NPRR1244		
Revision Description	This Nodal Operating Guide Revision Request (NOGRR) clarifies that a Controllable Load Resource is only required to provide Primary Frequency Response when it is providing an Ancillary Service that requires the Controllable Load Resource to be capable of providing Primary Frequency Response.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission		

Board Report

	☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	A Controllable Load Resource is a Load Resource that is capable of controllably reducing or increasing consumption under Dispatch control by ERCOT. A Controllable Load Resource may also be able to provide Primary Frequency Response but should not be required to be capable of providing Primary Frequency Response unless it is providing an Ancillary Service that requires this capability as detailed in Protocol Section 3.6.1, Load Resource Participation. A Controllable Load Resource that has blockier consumption can comply with Dispatch control by ERCOT but may not have the granular level of Dispatch control necessary to provide Primary Frequency Response. This NOGRR clarifies that a Controllable Load Resource that does not want to be eligible to provide an Ancillary Service to ERCOT that requires the capability to provide Primary Frequency Response may be exempt from ERCOT testing to verify its ability to provide Primary Frequency Response. This clarification allows additional Load Resources to qualify as Controllable Load Resources for all other purposes and thereby provides ERCOT greater visibility and control over such Load Resources.
ROS Decision	On 5/2/24, ROS voted unanimously to table NOGRR263 and refer the issue to the Performance, Disturbance, Compliance (PDCWG) Working Group. All Market Segments participated in the vote. On 8/1/24, ROS voted unanimously to recommend approval of NOGRR263 as amended by the 7/22/24 Priority Power comments. All Market Segments participated in the vote. On 9/9/24, ROS voted unanimously to endorse and forward to TAC the 8/1/24 ROS Report as revised by ROS and the 9/6/24 Impact Analysis for NOGRR263. All Market Segments participated in the vote.
Summary of ROS Discussion	On 5/2/24, the sponsor provided an overview of NOGRR263. Participants requested to table NOGRR263 and refer it to PDCWG for further review.

	On 8/1/24, ROS reviewed PDCWG discussion and the 7/22/24 Priority Power comments. On 9/9/24, ROS reviewed the 9/6/24 Impact Analysis and retitled NOGRR263 to reference NPRR1244.
TAC Decision	On 9/19/24, TAC voted unanimously to recommend approval of NOGRR263 as recommended by ROS in the 9/9/24 ROS Report; and the 9/13/24 Revised Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 9/19/24, participants reviewed the 9/13/24 Revised Impact Analysis.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NOGRR263 as recommended by TAC in the 9/19/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR263.
ERCOT Opinion	ERCOT supports approval of NOGRR263. ERCOT Staff has reviewed NOGRR263 and believes that it provides a positive market impact to enable a Load Resource to register as a Controllable Load Resource even if it is not capable of providing Primary Frequency Response. Specifically, this NOGRR enables Controllable Load Resources that are not capable of providing Primary Frequency Response to be eligible to provide ERCOT Contingency Reserve Service (ECRS) and Non-Spinning Reserve (Non-Spin). A

	Controllable Load Resource that is capable of providing Primary Frequency Response will continue to be required to respond to frequency disturbances with a Governor droop.
ERCOT Market Impact Statement	No impact (There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1244.)

Sponsor	
Name	Jim Gant
E-mail Address	jgant@prioritypower.com
Company	Priority Power Management LLC
Phone Number	
Cell Number	214-562-1807
Market Segment	Independent Retail Electric Provider (IREP)

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

Comments Received	
Comment Author	**Comment Summary**
Priority Power 072224	Provided clarifications to Section 2.2.8 and incorporated edits to Section 8, Attachment J, to enable a Load Resource to register as a Controllable Load Resource even if it is not capable of providing Primary Frequency Response, while still allowing the Resource to be eligible to provide ECRS and Non-Spin Service

Market Rules Notes

None

Proposed Guide Language Revision

2.2.8 Performance/Disturbance/Compliance Analysis

(1) Performance/Disturbance/Compliance analysis shall be performed by ERCOT for the purpose of ensuring conformance with the Protocols and Operating Guides. All

Generation Resources, ESRs, Controllable Load Resources that are capable of providing Primary Frequency Response, SOTGs, and SOTSGs~~, and Controllable Load Resources~~, except nuclear-powered Resources~~, Controllable Load Resources when not providing an Ancillary Service that requires the capability of providing Primary Frequency Response,~~ or WGRs with a permanent exemption approved by ERCOT, must respond to frequency disturbances with a Governor droop as specified in Section 2.2.7, Turbine Speed Governors. Each Generation Resource, ESR, Controllable Load Resource qualified for Regulation Service and/or RRS, SOTG, and SOTSG~~, and Controllable Load Resource~~ based on participation in at least eight FMEs, shall meet a minimum 12-month rolling average initial Primary Frequency Response performance and sustained Primary Frequency Response performance of 0.75 as calculated in Section 8, Attachment J, Initial and Sustained Measurements for Primary Frequency Response. When assessing conformance with the Protocols and Operating Guides, ERCOT shall evaluate the annual rolling average and may exclude from the performance analysis Generation Resources, ESRs, Controllable Load Resources qualified for Regulation Service and/or RRS, SOTGs, or SOTSGs~~, or Controllable Load Resources~~ in accordance with, but not limited to, the following conditions:

(a) Operating within the larger of five MW or 2% of the High Sustained Limit (HSL) or the maximum capacity for low frequency disturbances;

(b) Operating within the larger of five MW or 2% of the HSL or the maximum capacity above the LSL for high frequency disturbances;

(c) For an ESR, while discharging, if operating within the larger of 3 MW or 2% of the Maximum Operating Discharge Power Limit for low frequency disturbances;

(d) For an ESR, while charging, if operating within the larger of 3 MW or 2% of the Maximum Operating Charge Power Limit for high frequency disturbances;

(e) For any Generation Resource carrying power augmentation, the maximum capacity will be computed as the HSL minus Non-Frequency Responsive Capacity (NFRC); or

(f) Having a technical or physical limitation filed with the ERCOT client representative and approved by ERCOT.

(2) Market Participants shall request an exemption from, or correction of, performance during an FME within 30 days of the MIS posting date of the "Initial and Sustained Frequency Response Unit Performance" report.

(3) ERCOT will, on an as needed basis, utilize the Performance, Disturbance, Compliance Working Group (PDCWG) as a technical resource in providing input for types of technical or physical limitations that may be approved by ERCOT.

(4) ERCOT shall make a regular report on selected system disturbances, documenting the response of individual Generation Resources, ESRs, and Controllable Load Resources. In addition, Resource Entities, QSEs, and individual members of the PDCWG are

encouraged to work within their respective companies to enhance the performance of individual Generation Resource's, ESR's, or Controllable Load Resource's control systems through application of the results of the PDCWG studies.

ERCOT Nodal Operating Guides
Section 8
Attachment J

Initial and Sustained Measurements for Primary Frequency Response

~~December 9, 2022~~TBD

INITIAL PRIMARY FREQUENCY RESPONSE PERFORMANCE CALCULATION METHODOLOGY

This section establishes the process used to calculate initial Primary Frequency Response (PFR) performance for each Frequency Measurable Event (FME) for Generation Resources, Energy Storage Resources (ESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Self-Generators (SOTSGs), and Controllable Load Resources that are subject to this evaluation.

This process calculates the initial Per Unit PFR of a Resource ($P.U.PFR_{Resource}$) as a ratio between the Adjusted Actual PFR ($APFR_{Adj}$), adjusted for the pre-event ramping of the unit, and the Final Expected PFR ($EPFR_{final}$) as calculated using the Pre-perturbation and Post-perturbation time periods of the initial measure.

This comparison of actual performance to a calculated target value establishes, for each type of Resource, the initial $P.U.PFR_{Resource}$ for any FME.

Initial Primary Frequency Response Measurement

$P.U.PFR_{Resource}$ is the per unit measure of the initial PFR of a Resource during identified FMEs.

$$P.U.PFR_{Resource} = \frac{Actual\ Primary\ Frequency\ Response_{Adj}}{Expected\ Primary\ Frequency\ Response_{final}}$$

Where $P.U.PFR_{Resource}$ for each FME is limited to values between 0.0 and 2.0.

The Adjusted Actual PFR ($APFR_{Adj}$) and the Final Expected PFR ($EPFR_{final}$) are calculated as described below.

EPFR calculations use Governor droop and Governor Dead-Band values as stated in Section 2.2.7, Turbine Speed Governors, with the exception of combined-cycle facilities while being evaluated as a single resource (MW production of both the combustion turbine generator and the steam turbine generator are included in the evaluation) where the evaluation Governor droop will be 5.78%

Actual Primary Frequency Response ($APFR_{adj}$)

The Adjusted Actual Primary Frequency Response ($APFR_{adj}$) is the difference between Post-perturbation Average MW and Pre-perturbation Average MW, including the ramp magnitude adjustment.

$$APFR_{adj} = MW_{post-perturbation} - MW_{pre-perturbation} - Ramp\ Magnitude$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2

$$MW_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\,Scans}$$

Post-perturbation Average MW: Actual MW averaged from T+20 to T+52

$$MW_{post\ perturbation} = \frac{\sum_{T\ 20}^{T\ 52} MW}{\# Scans}$$

Ramp Adjustment: The Actual PFR number that is used to calculate $P.U.PFR_{Resource}$ is adjusted for the ramp magnitude of the generating unit/generating facility during the pre-perturbation minute. The ramp magnitude is subtracted from the APFR.

Ramp Magnitude = $(MW_{T-4} - MW_{T-60})*0.59$

$(MW_{T-4} - MW_{T-60})$ represents unit's MW ramp for a full minute prior to the FME. The factor 0.59 adjusts this full minute ramp to represent the ramp that should have been achieved during the post-perturbation measurement period.

Expected Primary Frequency Response (EPFR)

For all Generation Resources, ESRs, SOTGs, SOTSGs, and Controllable Load Resources, the ideal Expected PFR ($EPFR_{ideal}$) is calculated as the difference between the $EPFR_{post\text{-}perturbation}$ and the $EPFR_{pre\text{-}perturbation}$.

$$EPFR_{ideal} = EPFR_{post-perturbation} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor Dead-Band and above 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 - deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

When the frequency is outside the Governor Dead-Band and below 60Hz:

$$EPFR_{pre-perturbation} = \left[\frac{(HZ_{pre-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

$$EPFR_{post-perturbation} = \left[\frac{(HZ_{post-perturbation} - 60.0 + deadband_{max})}{(60 \times droop_{max} - deadband_{max})} \times (-1) \times (HSL - PA\ Capacity)\right]$$

For each formula, when frequency is within the Governor Dead-Band the appropriate EPFR value is zero. The $deadband_{max}$ and $droop_{max}$ quantities come from Section 2.2.7, Turbine Speed Governors.

Where:

Pre-perturbation Average Hz: Actual Hz averaged from T-16 to T-2

$$Hz_{pre-perturbation} = \frac{\sum_{T-16}^{T-2} Hz}{\# Scans}$$

Post-perturbation Average Hz: Actual Hz averaged from T+20 to T+52

$$Hz_{post-perturbation} = \frac{\sum_{T+20}^{T+52} Hz}{\# Scans}$$

Power Augmentation: For combined cycle facilities, Real-Time telemetered High Sustained Limit (HSL) is adjusted by subtracting the Real-Time telemetered Non-Frequency Responsive Capacity (power augmentation (PA) capacity). Other generator types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The Resource Entity should provide ERCOT with documentation and conditions when power augmentation is to be considered in PFR calculations as described in paragraph (11) of Protocol Section 6.5.5.2, Operational Data Requirements.

$EPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$EPFR_{final} = EPFR_{ideal} + \left(HZ_{post-perturbation} - 60.0\right) \times 10 \times 0.00276 \times (HSL - PA\ Capacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in combustion turbine's output due to the change in mass flow through the combustion turbine due to the speed change of the turbine during the post-perturbation measurement period. This factor is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.

$EPFR_{final}$ for Steam Turbine

$$EPFR_{final} = \left(EPFR_{ideal} + MW_{adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{adj} = EPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PA\ Capacity) \times Steam\ Flow\ Change\ Factor \times -1$$

where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure = Interpolation of Pressure curve at $MW_{pre\text{-}perturbation}$

The rated throttle pressure and the pressure curve, based on generator MW output, are submitted to ERCOT. This pressure curve is defined by up to six pair of pressure and MW breakpoints with the throttle pressure/MW output pair where rated throttle pressure is achieved as the first set and the throttle pressure/MW output pair where the minimum throttle pressure is achieved, as the last set of breakpoints. If fewer breakpoints are needed, the pair values will be repeated for different MW outputs (i.e., MW cannot be repeated on throttle pressure) to complete the six pair table.

The K factor is used to model the stored energy available to the Resource. The value ranges between 0.0 and 0.6 psig per MW change when responding during an FME. The Resource Entity can measure the drop in throttle pressure when the Resource is operating near 50% output of the steam turbine during an FME and provide this ratio of pressure change to ERCOT. K is then adjusted based on rated throttle pressure and Resource capacity. An additional sensitivity factor, the steam flow change factor, is based on resource loading (% steam flow) and further modifies the MW adjustment. This sensitivity factor will decrease the adjustment at Resource outputs below 50% and increase the adjustment at outputs above 50%. The Resource Entity should determine the fixed K factor for each Resource that generally results in the best match between EPFR and APFR (resulting in the highest $P.U.PFR_{Resource}$). For any generating unit, K will not change unless the steam generator is significantly reconfigured.

$EPFR_{final}$ for Other Generating Units/Generating Facilities and Energy Storage Resources

$$EPFR_{final} = EPFR_{ideal} + X$$

Where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the Resource. X may be adjusted by ERCOT and may be variable across the operating range of a resource. X shall be zero unless ERCOT accepts an alternative value.

SUSTAINED PRIMARY FREQUENCY RESPONSE PERFORMANCE CALCULATION METHODOLOGY

This section establishes the process used to calculate sustained Primary Frequency Response (PFR) performance for each Frequency Measurable Event (FME).

This process calculates the Per Unit Sustained PFR of a Resource ($P.U.SPFR_{Resource}$) as a ratio between the maximum actual unit response at any time during the period from T+46 to T+60, adjusted for the pre-event ramping of the unit, and the *Final* Expected Primary Frequency Response (EPFR) value at time T+46.[1]

This comparison of actual performance to a calculated target value establishes, for each type of Resource, the $P.U.SPFR_{Resource}$ for any FME.

Sustained Primary Frequency Response performance measurement:

Sustained Primary Frequency Response Calculation (P.U.SPFR)

$$P.U.SPFR_{\text{Resource}} = \frac{\text{Actual Sustained Primary Frequency Response}_{Adj}}{\text{Expected Sustained Primary Frequency Response}_{final}}$$

$P.U.SPFR_{Resource}$ is the per unit (P.U.) measure of the sustained PFR of a Resource during identified FME. The $P.U.SPFR_{Resource}$ for each FME will be limited to values between 0.0 and 2.0.

Actual Sustained Primary Frequency Response (ASPFR) Calculations

$$ASPFR = MW_{MaximumResponse} - MW_{pre-perturbation}$$

where:

Pre-perturbation Average MW: Actual MW averaged from T-16 to T-2.

$$MW_{pre\ -\ perturbation} = \frac{\sum_{T-16}^{T-2} MW}{\#\ Scans}$$

and:

[1] The time designations used in this section refer to relative time after an FME occurs. For example, "T+46" refers to 46 seconds after the frequency deviation occurred.

$MW_{MaximumResponse}$ = maximum MW value telemetered by a unit from T−46 through T+60 during low frequency FMEs and the minimum MW value telemetered by a unit from T−46 through T−60 during a high frequency FME.

Actual Sustained Primary Frequency Response, Adjusted ($ASPFR_{Adj}$)

$$ASPFR_{Adj} = ASPFR - RampMW\ Sustained$$

RampMW Sustained (MW) – Generation Resources, Energy Storage Resources (ESRs), Settlement Only Transmission Generators (SOTGs), Settlement Only Transmission Generators (SOTSGs), and Controllable Load Resources are required to sustain their response to an FME. An adjustment available in determining sustained Primary Frequency Response (PFR) performance ($P.U.SPFR_{Resource}$) is to account for the direction in which a Resource was moving (increasing or decreasing output) when the FME occurred T=t(0). This is the *RampMW* Sustained adjustment:

RampMW Sustain*ed* = ($MW_{T-4} - MW_{T-60}$) x 0.821

Note: The terminology "MW_{T-4}" *refers to MW output at 4 seconds before the FME occurs at T−t(0).*

By subtracting a reading at 4 seconds before, from a reading at 60 seconds before, the formula calculates the MWs a generator moved in the minute (56 seconds) prior to T=t(0). The formula is then modified by a factor to indicate where the unit would have been at T+46, had the FME not occurred: the "*RampMW Sustained.*" It does this by multiplying the MW change over 56 seconds before the event ($MW_{T-4} - MW_{T-60}$) by a modifier. This extrapolates to an equivalent number of MWs the generator would have changed if it had been allowed to continue on its ramp to T+46 unencumbered by the FME. The modifier is $\frac{46\ seconds}{56\ seconds}$ or 0.821.

<u>Expected Sustained Primary Frequency Response (ESPFR) Calculations</u>

The Expected Sustained Primary Frequency Response ($ESPFR_{final}$) is calculated using the actual frequency at T+46, HZ_{T+46}.

This $ESPFR_{final}$ is the MW value a Generation Resource, ESR, SOTG, SOTSG, or Controllable Load Resource should have responded with, if it is properly sustaining the output of its generating unit/generating facility in response to an FME. Determination of this value begins with establishing where it would be in an ideal situation; considers proper Governor droop and Governor Dead-Band values established in Section 2.2.7, Turbine Speed Governors, High Sustained Limit (HSL), Low Sustained Limit (LSL) and actual frequency. It then allows for adjusting the value to compensate for the various types of limiting factors each Generation Resource, ESR, SOTG, SOTSG, or Controllable Load Resource may have and any Non-

Frequency Responsive Capacity (NFRC) that may be included in the HSL.

Establishing the Ideal Expected Sustained Primary Frequency Response

For Generation Resources, ESRs, SOTGs, SOTSGs, and Controllable Load Resources, the ideal Expected Sustained PFR ($ESPFR_{ideal}$) is calculated as the difference between the $ESPFR_{T+46}$ and the $EPFR_{pre\text{-}perturbation}$. The $EPFR_{pre\text{-}perturbation}$ is the same $EPFR_{pre\text{-}perturbation}$ value used in the Initial measure.

$$ESPFR_{ideal} = ESPFR_{T+46} - EPFR_{pre-perturbation}$$

When the frequency is outside the Governor Dead-Band and above 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 - deadband_{\max})}{(droop_{\max} \times 60 - deadband_{\max})} \times (HSL - \text{PA Capacity}) \times (-1) \right]$$

When the frequency is outside the Governor Dead-Band and below 60Hz:

$$ESPFR_{T+46} = \left[\frac{(HZ_{T+46} - 60 + deadband_{\max})}{(droop_{\max} \times 60 - deadband_{\max})} \times (HSL - \text{PA Capacity}) \times (-1) \right]$$

For combined cycle facilities, determination of frequency responsive capacity includes subtracting power augmentation (PA) capacity, if any, from the original telemetered HSL. Other generator types may also have power augmentation that is not frequency responsive. This could be "over-pressure" operation of a steam turbine at valves wide open or operating with a secondary fuel in service. The Resource Entity is required to provide ERCOT with documentation and conditions when power augmentation is to be considered in PFR calculations as described in paragraph (11) of Protocol Section 6.5.5.2, Operational Data Requirements.

$ESPFR_{final}$ for Combustion Turbines and Combined Cycle Facilities

$$ESPFR_{final} = ESPFR_{Ideal} + (HZ_{T+46} - 60) * 10 * 0.00276 * (HSL - PACapacity)$$

Note: The 0.00276 constant is the MW/0.1 Hz change per MW of capacity and represents the MW change in combustion turbine's output due to the change in mass flow through the combustion turbine due to the speed change of the turbine at HZT+46. (This is based on empirical data from a major 2003 event as measured on multiple combustion turbines in ERCOT.)

ESPFR$_{final}$ for Steam Turbine

$$ESPFR_{final} = \left(ESPFR_{ideal} + MW_{Adj}\right) \times \frac{Throttle\ Pressure}{Rated\ Throttle\ Pressure}$$

where:

$$MW_{Adj} = ESPFR_{ideal} \times \frac{K}{Rated\ Throttle\ Pressure} \times (HSL - PACapacity) \times Steam\ Flow\ Change\ Factor \times (-1)$$

where:

$$\%\ Steam\ Flow = \frac{MW_{post-perturbation}}{(HSL - PA\ Capacity)}$$

$$Steam\ Flow\ Change\ Factor = \frac{\%\ Steam\ Flow}{0.5}$$

Throttle Pressure − Interpolati*on of* Pressur*e* curv*e* a*t* MW$_{pre\text{-}perturbation}$

ESPFRfinal for Other Generating Units/Generating Facilities and Energy Storage Resources

$$ESPFR_{final} = ESPFR_{Ideal} + X$$

where X is an adjustment factor that may be applied to properly model the delivery of PFR. The X factor will be based on known and accepted technical or physical limitations of the resource. X may be adjusted by ERCOT and may be variable across the operating range of a resource. X shall be zero unless ERCOT accepts an alternative value.

LIMITS ON CALCULATION OF PFR PERFORMANCE (INITIAL & SUSTAINED)

For frequency deviations below 60Hz (HZ$_{post\text{-}perturbation}$ < 60)
If for a generating unit/generating facility

$$MW_{Pre-Perturbation} \geq \min\left([(HSL - PA\ capacity) * 0.98], [(HSL - PA\ capacity) - 5MW]\right)$$

Then Primary Frequency Response is not evaluated for this Frequency Measurable Event (FME).
For frequency deviations above 60Hz ($HZ_{post\text{-}perturbation} > 60$)
If for a generating unit/generating facility

$$MW_{Pre-Perturbation} \leq \max\left([LSL + (HSL - PA\ capacity) * 0.02], [LSL + 5MW]\right)$$

Then Primary Frequency Response is not evaluated for this FME.

For Energy Storge Resources (ESRs), while discharging, if operating within the larger of 3 MW or 2% of the Real-Time Maximum Operating Discharge Power Limit for low frequency disturbances then Primary Frequency Response is not evaluated for this FME.

For ESRs, while charging, if operating within the larger of 3 MW or 2% of the Real-Time Maximum Operating Charge Power Limit for high frequency disturbances then Primary Frequency Response is not evaluated for this FME.

When Expected Primary Frequency $Response_{Final}$ is greater than operating margin Caps and limits exist for resources operating with adequate reserve margin to be evaluated (greater of 2% of (High Sustained Limit (HSL) less PA Capacity) or 5 MW), but with Expected Primary Frequency $Response_{Final}$ greater than the actual margin available.

(1) The $\mathrm{P.U.PFR_{Resource}}$ will be set to the greater of 0.75 or the calculated $\mathrm{P.U.PFR_{Resource}}$ if all of the following conditions are met:

(a) The generating unit/generating facility's or ESR's pre-perturbation operating margin (appropriate for the frequency deviation direction) is greater than 2% of its $(\mathrm{HSL - PACapacity})$ and greater than 5 MW; and

(b) The $\mathrm{EPFR_{Final}}$ is greater than the generating unit/generating facility's or ESR's available frequency responsive capacity[2]; and

(c) The generating unit/generating facility's or ESR's $\mathrm{APFR_{Adj}}$ response is in the correct direction.

(2) When calculation of the $\mathrm{P.U.PFR_{Resource}}$ uses the resource's $\mathrm{HSL - PACapacity}$ as the maximum expected output, the calculated $\mathrm{P.U.PFR_{Resource}}$ will not be greater than 1.0.

(3) When calculation of the $\mathrm{P.U.PFR_{Resource}}$ uses the resource's $\mathrm{LSL - PACapacity}$ as the minimum expected output, the calculated $\mathrm{P.U.PFR_{Resource}}$ will not be greater than 1.0.

[2] In this circumstance, when frequency is below 60 Hz, the EPFR_final is set to operating margin based on HSL (adjusted for any augmentation capacity) AND when frequency is above 60 Hz, the EPFR_final is set to operating margin based on LSL for the purpose of calculating PUPFR_resource.

(4) If the $\mathrm{APFR_{Adj}}$ is in the wrong direction, then $\mathrm{P.U.PFR_{Resource}}$ is 0.0.

(5) These caps and limits apply to both the Initial and Sustained Primary Frequency Response measures.

INITIAL PFR and SUSTAINED PFR PERFORMANCE REQUIREMENT

ERCOT computes an average Initial PFR and Sustained PFR performance based on either all FMEs evaluated within 12 months or the last eight FMEs (applicable if a minimum threshold of eight FMEs within the 12 month period is not met). Each Generation Resource, ESR, Settlement Only Transmission Generator (SOTG), Settlement Only Transmission Self-Generator (SOTSG), and Controllable Load Resource shall meet a minimum rolling average initial Primary Frequency Response performance and sustained Primary Frequency Response performance of 0.75.

Initial PFR requirement:

$$Avg_{Period}[P.U.PFR_{Resource}] \geq 0.75,$$

Sustained PFR requirement:

$$Avg_{Period}[P.U.SPFR_{Resource}] \geq 0.75$$

Revised ERCOT Impact Analysis Report

NOGRR Number	**263**	**NOGRR Title**	**Related to NPRR1244, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities**
Impact Analysis Date		September 13, 2024	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Nodal Operating Guide Revision Request (NOGRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1244, Clarification of Controllable Load Resource Primary Frequency Response Responsibilities.	
ERCOT Staffing Impacts (across all areas)		Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

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

Comments
There are no additional impacts to this NOGRR beyond what was captured in the Impact Analysis for NPRR1244.

Board Report

OBDRR Number	**046**	**OBDRR Title**	**Related to NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources**
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon implementation of Nodal Protocol Revision Request (NPRR) 1188, Nodal Dispatch and Energy Settlement for Controllable Load Resources		
Priority and Rank Assigned	Not applicable		
Other Binding Document Requiring Revision	Procedure for Identifying Resource Nodes		
Supporting Protocol or Guide Section(s) / Related Documents	NPRR1188		
Revision Description	This Other Binding Document Revision Request (OBDRR) aligns the Procedure for Identifying Resource Nodes with the revisions from NPRR1188 to accommodate nodal Dispatch and Settlement of Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs).		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☐ Administrative ☐ Regulatory requirements ☒ ERCOT Board and/or PUCT Directive		

Board Report

	(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)
Justification of Reason for Revision and Market Impacts	Alignment between the Protocols and Other Binding Documents is necessary and proper.
TAC Decision	On 7/25/23, TAC voted unanimously to table OBDRR046. All Market Segments participated in the vote. On 9/19/24, TAC voted unanimously to recommend approval of OBDRR046 as submitted and the 6/27/23 Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 7/25/23, there was no discussion. On 9/19/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed ☐ Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of OBDRR046 as recommended by TAC in the 9/19/24 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on OBDRR046.
ERCOT Opinion	ERCOT supports approval of OBDRR046.
ERCOT Market Impact Statement	ERCOT Staff has reviewed OBDRR046 and believes the market impact for OBDRR046, along with NPRR1188, implements nodal pricing and Settlement for CLRs and provides several positive

	impacts, including increased efficiency of the DAM and improved CLR visibility to ERCOT operations and markets.

Sponsor	
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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Please note that the following OBDRR(s) also propose revisions to this OBD:

- OBDRR052, Related to NPRR1246, Energy Storage Resource Terminology Alignment for the Single-Model Era

Proposed Other Binding Document Language Revision

Introduction:

Commented [CP1]: Please note OBDRR052 also proposes revisions to this OBD

This procedure is the guiding document for ERCOT and Market Participants with Generation Resources or Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs), to identify Resource Nodes and manage the lifecycle of the Resource Node.

Revisions to this document must be approved by the Technical Advisory Committee (TAC). In the following cases, after review and recommendation by TAC, revisions to this document must be approved by the ERCOT Board:

a. The revisions require an ERCOT project for implementation; and

b. The revisions are related to a Nodal Protocol Revision Request (NPRR), a Planning Guide Revision Request (PGRR), or a revision request requiring an ERCOT project for implementation.

Upon approval of revisions, ERCOT shall post the revised procedure to the ERCOT website within three Business Days.

Procedure to Incorporate a Resource Node into the Network Operations Model:

1. At the designated time period as determined by Protocol Section 3.10, Network Operations Modeling and Telemetry, and associated ERCOT business processes, a Resource Entity must submit Resource Registration information that includes a detailed electrical one-line drawing of the generation facility. The ERCOT business process indicates that the Resource Registration information will be presented to the Network Modeling Group within ERCOT.
2. The Network Modeling Group will utilize the "Principles for Resource Node Definition" located in Appendix A to determine the Resource Node parameters.
3. The Network Modeling Group will provide documentation back to the Resource Entity clearly indicating the Resource Node parameters.
4. The Resource Entity will have five Business Days to accept or reject the suggested Resource Node parameters.
5. If there are any disagreements with the Resource Node parameters, ERCOT and the Resource Entity shall work together to reach agreement.
6. If agreement cannot be reached by ERCOT and the Resource Entity, the Wholesale Market Subcommittee (WMS) or appropriate WMS working group shall help guide the decision.
7. Upon an agreement between ERCOT and the Resource Entity, the Resource Node parameters will be implemented in the Network Operations Model.
8. The normal timeline for this procedure shall not exceed 20 Business Days after the submission date of validated Resource Registration information that includes a detailed electrical one-line drawing.
9. In the event that agreement between ERCOT and the Resource Entity cannot be reached within 20 Business Days, no Resource Node parameters will be entered into the Network Operations Model. This may have an effect on Congestion Revenue Right (CRR) Network Models and associated CRR activities regarding the Generation Resource or CLR in question. There must be an agreement between ERCOT and the Resource Entity before Resource Node parameters will be implemented into the Network Operations Model.
10. Once effective in the Network Operations Model, the Resource Node name cannot be changed.
11. Once incorporated into the Network Operations Model, the Resource Node will be used in all associated ERCOT models, applications, and processes.
12. The Resource Node parameters, associated electrical one-line drawings, and other relevant data shall be posted on the Market Information System (MIS) Secure Area and will be available to Market Participants with Digital Certificates.

Procedure to Retire a Resource Node in the Network Operations Model:

1. Resource Nodes cannot be retired until all outstanding CRRs on that Resource Node have been settled. Transmission Service Providers (TSPs) cannot submit Network Operations Model Change Requests (NOMCRs) to delete a Resource Node.

2. ERCOT's ~~CRR~~ Forward Markets team will identify a nearby energized bus to move the location of the retiring Resource Node to until such time as all the outstanding CRRs are settled once it has been notified that equipment tied to a Resource Node is requested to be removed from the Network Operations Model. In this specific case, the Resource Node location will not follow the rules in this document, and it may not be located near a Generation Resource or CLR.

3. ERCOT's CRR team will submit a NOMCR with the appropriate effective date to remove the retiring Resource Node in the future. The effective date is determined based on the last active CRR date.

4. ERCOT's Day-Ahead Market (DAM) team will update the Resource Node expiration date in the Market Management System (MMS) based on the retirement of the Resource Node.

Appendix A

PRINCIPLES FOR RESOURCE NODE DEFINITION

1. Network Operations Model

a. Annual/Monthly CRR Auctions use a network model as close as possible to the Network Operations Model.

b. MMS and Energy Management System (EMS) use the same Network Operations Model for both commercial and operational purposes.

c. Breakers between the Resource Connectivity Nodes and the Resource Node are assumed closed by default so that Resource Nodes and associated Resource Connectivity Nodes appear energized.

d. Transmission Element Outages, as defined in the Protocols, are submitted into the Outage Scheduler and posted before DAM submission, i.e. de-energized Resource Nodes (Settlement Points) are known in advance of DAM submission.

2. Resource Connectivity Nodes

a. Resource Connectivity Node represents the Electrical Bus where the physical generator is connected or the Electrical Bus of a Common Information Model (CIM) Load that a CLR is mapped to.

b. Generator output is injected at the Resource Connectivity Node and CLR consumption is withdrawn at the Resource Connectivity Node.

c. More than one Resource can be connected to the same Resource Connectivity Node.

3. Resource Nodes

3.1 Resource Node Definition

a. Resource Node represents the Electrical Bus or the logical construct that defines the location of a Settlement Point.

b. Resource Nodes include Generation/CLR Resource Nodes, Combined Cycle Plant (CCP) Logical Resource Nodes, Combined Cycle Unit (CCU) Resource Nodes and Private Use Network (PUN) Resource Nodes. Note that for an ESR, the Resource Node for both the Generation Resource component as well as the CLR component is the same and the location of this single Resource Node for both components of the ESR is based on the guidelines described in this document for the placement of Resource Nodes for a Generation Resource.

c. Generation/CLR Resource Nodes represents the Settlement Points for ERCOT and PUN Generation Resources and CLRs. The Three-Part Supply Offers, Energy Bid Curves, DAM Energy-Only Offers, Ancillary Service Offers and DAM Energy Bids as well as Point-to-Point (PTP) bids can be submitted and settled at a Generation/CLR Resource Node, unless that Generation/CLR Resource Node is within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and ERCOT-Polled Settlement (EPS) Meter, in which case only Three-Part Supply Offers, Energy Bid Curves, and Ancillary Service Offers can be submitted and settled.

   i. Generation/CLR Resource Nodes within a PUN site refers to those Resource Nodes defined for Generation Resources and/or CLRs within a PUN site that cannot be placed at the PUN Point of Interconnection (POI) due to the rules for placement of Resource Nodes described in Section 3.2, Resource Node Location.

d. CCP Logical Resource Nodes represents the Settlement Points for Three-Part Supply Offers for CCP configurations. Only Three-Part Supply Offers~~,~~ and Ancillary Service Offers for CCP configurations can be submitted to be~~and~~ settled at a CCP Logical Resource Node.

e. CCU Resource Nodes represents the Settlement Points for the CCU. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted and settled at a CCU Resource Node.

f. PUN Resource Nodes represents the Settlement Points at the PUN interconnection to ERCOT. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted and settled at a PUN Resource Node.

g. Multiple Generation Resources and CLRs can be mapped to the same Resource Node, i.e. offers from different Generation Resources and/or bids from CLRs can be settled at the same Settlement Point.

h. A Generation Resource can only be mapped to one Resource Node, i.e. DAM offers from ~~the~~a Generation Resources can only be settled using~~at~~ one Settlement Point Price (SPP). A CLR can only be mapped to one Resource Node, i.e. DAM bids from a CLR can only be settled using one SPP.

i. The Resource Nodes for "single" Resources and for Resources that are a component of a CCP shall be identified prior to the identification of the PUN Resource Nodes. Once those Resource Nodes have been located, the PUN Resource Nodes shall be located for PUN Resources that are not co-located with an existing Resource Node.

j. Resource Nodes shall not be located at the Direct Current Ties (DC Ties). (The DC Ties are Load Zones.)

k. Resource Nodes shall not be located at the Block Load Transfer (BLT) buses.

l. Do not identify or locate Resource Nodes for ~~Non-Modeled Generators~~Settlement Only Resources.

Board Report

3.2 Resource Node Location

a. First Fork Rule: Locate Resource Node at the first Electrical Bus with alternate paths starting from the Generation Resource Connectivity Node for Generation Resources and the Connectivity Node of the CIM Load that a CLR is mapped to for CLRs. Parallel network paths do not count as alternate paths.

i. Exception: There is an exception to this rule for placing Generation/CLR Resource Nodes and CCU Resource Nodes that are mapped to Generation Resources/CLRs within a PUN. If the Generation Resource(s)/CLR(s) is within a PUN that has only one interconnection to the ERCOT Transmission Grid, locate the Resource Node at the Electrical Bus that is the interconnection point of the PUN to the ERCOT Transmission Grid.

ii. ERCOT-Polled Settlement (EPS) Meter ~~l~~Location ~~c~~Check: As the network connectivity path is traversed in searching for the first Electrical Bus with alternate paths (First Fork Rule), if an Electrical Bus is encountered with a mapped EPS Meter first, then place the Resource Node at this Electrical Bus. The Resource Node for an ESR is the same for both the Generation Resource and CLR components of the ESR. The placement of the Resource Node for the components of an ESR is governed by the guidelines in this document for a Generation Resource.

b. EPS Meter Rule: Locate Resource Node, subject to First Fork Rule, electrically as close as possible to EPS Meter location, i.e. where energy is effectively metered. If the EPS Meter location changes, then a new Resource Node must be established and the old Resource Node retired in accordance with the procedure in this document. Please refer to paragraph (h)(ii) below for a list of exceptions under which ERCOT can relocate a Resource Node.

c. Ownership Rule: Locate Resource Node at the Electrical Bus that is the ERCOT POI (if practical). Subsequent ownership changes shall not change the Resource Node location.

d. De-Energization Rule: Locate Resource Node at Electrical Bus that is less often de-energized, if alternate choices exist. ~~Settlement Point Prices (~~SPPs~~)~~ for de-energized Resource Nodes are calculated using heuristic rules.

e. Generic Transmission Constraint (GTC) Rule: A GTC cannot include Transmission Elements between a Resource Node and any Generation Resources or CLRs mapped to it.

f. Transmission Constraint Rule: Initial placement of the Resource Node should not be such that Transmission Elements between Resource Node and associated Resource Connectivity Nodes could be constrained. The parameters of the Network Operations Model are evaluated at that point in time when the determination of the Resource Node placement is being made such that there is no congestion between the location of the Resource Node and the Resource Connectivity Node that the Generation Resource is physically connected to, or the Connectivity Node of the CIM Load that the CLR is mapped to, in the Network Operations Model. Ongoing monitoring to ensure that there is no congestion between the Resource Node and the Resource Connectivity Node of the Generation Resource, or the Connectivity Node of the CIM Load that the CLR is mapped to, requires the Resource Entity and Transmission and/or Distribution Service Provider (TDSP) to monitor and coordinate changes that may impact this. See Articles 5, 6 and 7 of the Standard Generation Interconnection Agreement (SGIA).

g. Publicity Rule: Market Participants need to know where the Resource Nodes are located.

h. In the event of a subsequent NOMCR that changes the topology, ERCOT shall review the impact to the Resource Node location.

   i. In cases where a NOMCR, that is to be effective in the future, requires the placement of a new Resource Node, there may be instances where the Common Information Model (CIM) may show both the current and the future topology with the new Resource Node. This is done to handle situations where the energization date/time of the future network changes are different than the date/time of the migration of the changes in the network model into the ERCOT production systems. In such cases:

      A. The location of the new Resource Node will be based on the future topology only.

      B. The transition of the mapping between the Generation Resource or CLR and the new Resource Node (if applicable) will be performed by ERCOT support staff.

   ii. ERCOT may relocate the existing Resource Node to an appropriate location to:

      A. Align with the implementation of NPRR1016, Clarify Requirements for Distribution Generation Resources (DGRs) and Distribution Energy Storage Resources (DESRs), in the Network Operations Model;

      B. Account for a series compensator(s); or

      C. Implement station renames.

i. If all rules cannot be simultaneously satisfied, then the rules are listed in order of priority. ERCOT will use discretion in choosing the appropriate Resource Node location, assuming ~~that~~ such a location does not allow the Resource Entity to control its Resource Node price.

4. Combined Cycle Plant (CCP) Modeling

4.1 CCP Logical Resource Node

a. Each CCP configuration for a train represents a CCP Logical Generation Resource.

b. Each CCP Logical Generation Resource is mapped to a CCP Logical Resource Node. All CCP Logical Generation Resources, i.e. all CCP configurations for a train are mapped to the same CCP Logical Resource Node.

c. Each CCP train has its own CCP Logical Resource Node, i.e. CCP Logical Generation Resources for different CCP trains are mapped to different CCP Logical Resource Nodes.

d. Each CCP Logical Resource Node is a Settlement Point.

e. CCP Logical Resource Nodes are used only for Resource-specific Three-Part Supply Offers and Ancillary Service Offers for CCP configurations.

4.2 CCU Resource Node

a. CCU Resource Nodes are mapped to a CCP Logical Resource Node.

b. A CCU Resource Node is the Electrical Bus determined by above rules (First Fork and others as described in Section 3.2, Resource Node Location, above) starting from the Resource Connectivity Node of the physical CCP train Resources.

c. A CCU Resource Node is a Settlement Point.

d. Only DAM Energy-Only Offers, DAM Energy Bids and PTP bids can be submitted at CCU Resource Nodes.

4.3 CCP/CCU Resource Node Processing

a. PTP cleared quantities are injected at Electrical Buses of CCU Resource Nodes.

b. DAM SPP for CCU Resource Node is used as Settlement Price for PTP bids that sink or source at CCU Resource Node.

c. In DAM, energy for CCP Logical Resource is distributed to Connectivity Nodes of physical CCP Resources proportionally to the Resource capacities that are On-Line in the selected CCP configuration.

d. In DAM, Shift Factor for CCP Logical Resource Node Dispatch is calculated as the High Reasonability Limit (HRL) weighted average of Shift Factors for CCU Resource Connectivity Nodes using the Resource HRLs that are On-Line in the selected CCP configuration as weights. Note that the assumption here is that there is no congestion between the connectivity node of the CCU and the Resource Node.

e. DAM SPP for CCP Logical Resource Node is equal to weighted average of DAM SPPs at CCU Resource Nodes using the Resource HRLs that are On-Line in selected CCP configuration as weights. For an Off-Line CCP, the Locational Marginal Price (LMP) for the CCP Logical Resource Node is calculated as weighted average of LMPs at CCU Resource Nodes using the HRLs of the CCU Resources. Note that the assumption here is that there is no congestion between the Resource Connectivity Node of the CCU and the Resource Node.

f. DAM SPP for CCP Logical Resource Node is used as the Settlement Price for CCP Three-Part Supply Offers.

g. In Real-Time Market (RTM), Shift Factor for CCP Logical Resource Node is calculated as weighted average of Shift Factors for CCU Resource Connectivity Nodes using the telemetered outputs of CCU Resources that are online in current CCP configuration as weights. Note that the assumption here is that there is no congestion between the Resource Connectivity Node of the CCU and the Resource Node.

h. RTM ~~Locational Marginal Price (~~LMP~~)~~ for CCP Logical Resource Node when the CCP is On-Line is calculated based on the weighted average of Shift Factors at CCU Resource Connectivity Nodes using telemetered outputs of CCU Resources that are online in current CCP configuration as weights. For an Off-Line CCP, the LMP for the CCP Logical Resource Node is calculated as weighted average of LMPs at CCU Resource Nodes using the HRLs of the CCU Resources. Note that the assumption here is that there is no congestion between the Resource Connectivity Node of the CCU and the Resource Node.

i. RTM SPP for the CCP Logical Resource Node is the Base Point or time weighted average of RTM LMPs at Logical Resource Node.

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5. Private Use Network (PUN) Modeling

5.1 PUN Resource Node

a. The placement of a PUN Resource Node is optional. At a PUN, after all the Generation/CLR Resource Nodes, CCP Logical Resource Nodes and CCU Resource Nodes are placed (if applicable), if none of the Generation/CLR Resource Nodes or CCU Resource Nodes are placed where the EPS Meter is effectively located, then this is the location of the PUN Resource Node.

b. PUN Resource Node represents the Electrical Bus where an EPS Meter is effectively located that is measuring the flow at a POI with ERCOT.

c. PUN Resource Node is a Settlement Point.

d. PUN Resource Node cannot have mapped PUN Generation/CLR Resources.

e. There can be several PUN Resource Nodes for one PUN.

f. Only PTP and DAM Energy Bids and Energy-Only Offers can be submitted at a PUN Resource Node.

g. For DAM Energy-Only Offers, power is injected at the Electrical Bus of the PUN Resource Node.

h. DAM Cleared quantities are settled at PUN Resource Node ~~Settlement Prices~~SPP.

5.2 Resource Nodes for PUN Generation Resource/CLR

a. Resource Connectivity Node for PUN Generation Resource/CLR represents the Electrical Bus where physical Resource is connected or the Connectivity Node of the CIM Load that the CLR is mapped to.

b. Generator outputs are injected at Resource Connectivity Nodes and CLR consumption is withdrawn at the Resource Connectivity Nodes.

c. Resource Node for PUN Generation Resource/CLR represents the Electrical Bus where Settlement Point for PUN Generation Resource/CLR is located.

d. Resource Node for PUN Generation Resource/CLR is defined using First Fork Rule and others as described in Section 3.2, Resource Node Location, above.

e. A Resource Node for a PUN Generation Resource/CLR is a Settlement Point.

f. PUN energy offers represent net to grid in respect to PUN self-served load excluding CLR energy consumption. PUN CLR Energy Bid Curves represent the bid to buy of the CLR total energy consumption

g. Three-Part Supply Offer and Ancillary Service Offers can be submitted for PUN Generation Resource for the excess capacity and energy not used to serve the PUN self-serve Load. CLR Energy Bid Curves and Ancillary Service Offers can be submitted for PUN CLR for its total capacity.

h. DAM Resource-specific ~~Offers~~Energy Offer Curves and Energy Bid Curves for PUN Generation Resources/CLRs are settled ~~at~~using SPPs at Resource Nodes for PUN Generation Resources/CLRs.

i. Constraints within a PUN can be monitored but will not be enforced by DAM, Reliability Unit Commitment (RUC) and Security-Constrained Economic Dispatch (SCED).

j. Only PTP and DAM Energy Bids and DAM Energy-Only Offers can be submitted at PUN Resource Nodes.

5.3 CCP Modeling within a PUN

a. CCP trains within a PUN are treated in the same way as any CCP within ERCOT.

6. Settlement Points

a. Settlement Point is a Resource Node, Load Zone, or Hub.

b. Resource Nodes include Generation/CLR Resource Nodes, CCP Logical Resource Nodes, CCU Resource Nodes, and PUN Resource Nodes.

c. Generation/CLR Resource Nodes within ERCOT as well as within PUN are Settlement Points.

7. DAM Clearing and Settlements

a. PTP bids can be submitted using any Settlement Point (except Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter; and CCP Logical Resource Nodes) as a source and sink.

b. CRRs acquired at de-energized Settlement Points will not be considered by Simultaneous Feasibility Test (SFT) function.

c. DAM Energy-Only Offers can be submitted at any Settlement Point (except Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter; and CCP Logical Resource Nodes).

d. DAM Resource-specific energy offers that are submitted are mapped to a Generation Resource/CLR Node or a CCP Logical Resource Node only.

e. DAM Energy Bids can be submitted at Load Zones, Hubs, Generation/CLR Resource Nodes, CCU Resource Nodes and PUN Resource Nodes, ~~i.e.~~i.e., at any Settlement Point except Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter; and CCP Logical Resource Nodes.

f. DAM/Supplemental Ancillary Services Market (SASM) Ancillary Service Offers are Generation/Load Resource-specific, not Settlement Point-specific.

g. DAM scheduling determines hourly quantities for PTP, energy and Ancillary Service Offers and bids.

h. DAM pricing determines hourly LMPs for all Settlement Points.

i. DAM Settlements is based on DAM quantities and DAM SPPs.

8. RTM Clearing and Settlements

a. SCED dispatch determines Base Points for Generation Resources/CLRs.

b. SCED pricing determines LMPs for all Generation/CLR Resource Nodes, CCP Logical Resource Nodes, CCU Resource Nodes, PUN Resource Nodes and all EPS Meter locations.

c. RTM determines 15-minute SPPs for each Settlement Point and each EPS Meter location. These prices are the Base Point weighted and time weighted average of the Real-Time LMPs.

d. RTM Settlement~~s~~ uses 15-minute RTM SPPs (prices at Settlement Points) and Settlement ~~P~~prices (prices at EPS Meter locations).

e. RTM Energy Settlement for the measured output from the Generation Resources uses the prices at the EPS Meter locations as specified in Protocol Section 6.6.3, Real-Time Energy Charges and Payments.

f. RTM Energy Settlement for the measured consumption from the CLRs uses the prices at the EPS Meter locations as specified in Protocol Section 6.6.3, Real-Time Energy Charges and Payments.

9. Summary of Allowed Activities

	ACTIVITIES						
Settlement Points	**Three-Part Supply Offer**	**Ancillary Service Offer**	**DAM Energy-Only Offers**	**DAM Energy Bid**	**PTP bids (both in DAM & CRR**)**	**QSE to QSE Transaction**	**Energy Bid Curve**
Generation/CLR Resource Node not in a PUN site, or Generation/CLR Resource Node at a PUN where no constrainable Transmission Element(s) exist between the	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Generation/CLR Resource Node and EPS Meter							
Generation/CLR Resource Node within a PUN site* where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter	Yes	Yes	No	No	No	Yes	Yes
CCU Resource Node	No	No	Yes	Yes	Yes	Yes	No
PUN Resource Node	No	No	Yes	Yes	Yes	Yes	No
CCP Logical Resource Node	Yes	Yes	No	No	No	No	No

Note that Resource-specific offers (Three-Part Supply Offer, Energy Bid Curve, and Ancillary Service Offers) are made for the Resource and the submittal does NOT specify a Resource Node.

*These Generation/CLR Resource Nodes will be identified as such in the report NP4-500-SG, Day-Ahead Power System Simulator for Engineering (PSS/E) Network Operations Model and Supporting Files. CRR Auctions will use the most recent report available at the time the CRR Auction model is created.

**Generation/CLR Resource Nodes within a PUN site where constrainable Transmission Element(s) exist between the Generation/CLR Resource Node and EPS Meter will become non-biddable in CRR Auctions for CRR effective dates after December 31, 2020.

ERCOT Impact Analysis Report

OBDRR Number	**<u>046</u>**	**OBDRR Title**	**Related to NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources**
Impact Analysis Date		June 27, 2023	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Other Binding Document Revision Request (OBDRR) can take effect upon implementation of Nodal Protocol Revision Request (NPRR) 1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources	
ERCOT Staffing Impacts (across all areas)		Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		No impacts to ERCOT computer systems.	
ERCOT Business Function Impacts		No impacts to ERCOT business functions.	
Grid Operations & Practices Impacts		No impacts to ERCOT grid operations and practices.	

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

Comments
There are no additional impacts to this OBDRR beyond what was captured in the Impact Analysis for NPRR1188.

Board Report

RMGRR Number	181	RMGRR Title	Alignment of Defined Term Usage and Resolution of Inconsistencies
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Retail Market Guide Sections Requiring Revision	2.1, Definitions 5.3, Ad Hoc Retail Market Conference Calls 7.3, Inadvertent Gain/Loss Process 7.3.2.1.2, Breach of Contract 7.3.2.2, Prevention of Inadvertent Gains 7.3.2.4, Gaining CR System Processing Errors 7.3.2.5, Resolution of IAGs 7.3.2.5.1, Reinstatement Date 7.3.2.6, Valid Reject/Unexecutable Reasons 7.3.2.7, Invalid Reject/Unexecutable Reasons 7.3.2.8, Out-of-Sync Condition 7.3.2.9, No Losing Competitive Retailer of Record 7.3.3, Charges Associated with Returning the Customer 7.3.4.2, Inadvertent Order is Pending 7.3.4.4, Transmission and/or Distribution Service Provider Billing 7.3.5, Customer Rescission after Completion of a Switch Transaction 7.3.5.1, Additional Valid Reasons for Rejection of a Rescission-based Issue 7.10.4, Addition or Removal of Switch Hold by Retail Electric Provider of Record Request for 650 Transactions During Extended Unplanned System Outage Affecting the REP and/or TDSP 7.11.1, Transition Process of Competitive Retailer's Electric Service Identifiers to Provider of Last Resort or Designated Competitive Retailer Pursuant to P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR), or CR Voluntarily Leaving the Market 7.11.1.4.1.2, ERCOT Pre-Launch Responsibilities in a Mass Transition 7.11.1.4.2.2, ERCOT Responsibilities During the Mass Transition		

	7.11.1.4.2.3, Transmission and/or Distribution Service Provider Responsibilities During the Mass Transition 7.11.2, Acquisition and Transfer of Customers from one Retail Electric Provider to Another 7.11.2.4, Acquisition Transfer Roles/Responsibilities 7.11.2.4.2, ERCOT Responsibilities in an Acquisition Transfer 7.11.5, Transmission and/or Distribution Service Provider Electric Service Identifier Transition Roles and Responsibilities 7.11.6, Transmission and/or Distribution Service Provider Transition Process Narrative 7.16.4.3.1, Timelines Associated with Removal of a Switch Hold for Meter Tampering for Purposes of a Move in 7.16.4.3.2, Steps for Removal of a Switch Hold for Meter Tampering for Purposes of a Move in 7.16.4.3.3, Release of Switch Hold for Meter Tampering Due to Exceeding Specified Timelines 7.17.3.3.1, Timelines Associated with Removal of a Switch Hold for Deferred Payment Plans for Purposes of a Move in 7.17.3.3.2, Steps for Removal of a Switch Hold for Deferred Payment Plans for Purposes of a Move in 7.17.3.3.3, Release of Switch Hold for Payment Plans Due to Exceeding Specified Timelines
Related Documents Requiring Revision/Related Revision Requests	Nodal Protocol Revision Request (NPRR) 1227, Related to RMGRR181, Alignment of Defined Term Usage and Resolution of Inconsistencies
Revision Description	This Retail Market Guide Revision Request (RMGRR) aligns defined term usage in the Retail Market Guide with Protocol Section 2.1, Definitions, relocates four definitions from Section 2.1 ('Decision', Effective Date', 'Gaining Competitive Retailer', and 'Losing Competitive Retailer') to Protocol Section 2.1 since these definitions are used in both the Retail Market Guide and the Nodal Protocols, and removes the no-longer-needed defined term 'Target Effective Date.' This RMGRR also aligns greybox language in paragraph (4) of Section 7.3.2.5 with RMGRR170, Inadvertent Gain Process Updates, removes paragraph (1) from Sections 7.11.1 and 7.11.2 due to redundancy, and makes non-substantive clarifying changes to resolve inconsistencies in Sections 7.16.4.3.2, 7.16.4.3.3, 7.17.3.3.2, and 7.17.3.3.3.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience

Board Report

	☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvements ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This RMGRR clarifies language in the Retail Market Guide to enhance consistency, aid readability, and reduce the risk of misinterpretation. The edit to Section 7.3.2.5 replicates a language change made to paragraph (4) in RMGRR170 (which became effective on January 1, 2023) that was unintentionally omitted from corresponding greybox language. This RMGRR causes no impact to the market as it is not a process change.
RMS Decision	On 6/4/24, RMS voted unanimously to recommend approval of RMGRR181 as amended by the 5/28/24 TDTMS comments. All Market Segments participated in the vote. On 8/6/24, RMS voted unanimously to endorse and forward to TAC the 6/4/24 RMS Report and the 4/30/24 Impact Analysis for RMGRR181. All Market Segments participated in the vote.
Summary of RMS Discussion	On 6/4/24, RMS reviewed RMGRR181 and the 5/28/24 TDTMS comments. On 8/6/24, RMS reviewed the 4/30/24 Impact Analysis.
TAC Decision	On 8/28/24, TAC voted unanimously to recommend approval of RMGRR181 as recommended by RMS in the 8/6/24 RMS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/28/24, there was no additional discussion beyond TAC review of the items below.

Board Report

TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of RMGRR181 as recommended by TAC in the 8/28/24 TAC Report.

Opinions	
Credit Review	Not Applicable
Independent Market Monitor Opinion	IMM has no opinion on RMGRR181.
ERCOT Opinion	ERCOT supports approval of RMGRR181.
ERCOT Market Impact Statement	ERCOT Staff has reviewed RMGRR181 and believes that it provides a positive market impact by offering process improvements by relocating four, shared-use definitions from the Retail Market Guide to the Protocols; and by applying various, non-substantive alignment edits throughout the Retail Market Guide.

Sponsor	
Name	Jordan Troublefield
E-mail Address	jordan.troublefield@ercot.com
Company	ERCOT
Phone Number	512-248-6521
Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
Name	Jordan Troublefield

E-Mail Address	jordan.troublefield@ercot.com
Phone Number	512-248-6521

Comments Received	
Comment Author	**Comment Summary**
TDTMS 052824	Proposed a corrective, oversight edit to Section 7.3.5 associated with System Change Request (SCR) 817, Related to NPRR1095, MarkeTrak Validation Revisions Aligning with Texas SET V5.0, which was approved at the March 31, 2022 PUCT meeting

Market Rules Notes

Please note administrative changes have been made below and authored as "ERCOT Market Rules".

Please note the baseline language in the following Section(s) has been updated to reflect the incorporation of the following RMGRR(s) into the Retail Market Guide:

- RMGRR177, Switch Hold Removal Clarification (incorporated 7/1/24)
    - Section 7.16.4.3.2
    - Section 7.17.3.3.2

Proposed Guide Language Revision

2.1 DEFINITIONS

~~**Decision**~~

~~Parameters associated with a Mass Transition or Acquisition Transfer event that dictate the parties involved and the Target Effective Date of the Mass Transition or Acquisition Transfer. Decision parameters include designation of the Losing Competitive Retailer (CR), the Gaining CR, the preliminary list of transitioning Electric Service Identifiers (ESI IDs) and the Target Effective Date of the Mass Transition or Acquisition Transfer.~~

~~**Effective Date**~~

~~The date on which the Mass Transition or Acquisition Transfer of ESI IDs from the Losing CR to the Gaining CR is to take place. This is the date on which the meter read is taken and is used in Mass Transition or Acquisition Transfer transactions.~~

~~**Gaining Competitive Retailer**~~

~~CR identified in the initiating Decision who is to become the REP of record as of the Effective Date for a transitioned ESI ID following the Mass Transition or Acquisition Transfer.~~

Inadvertent Gain/Loss (IAG)

An unauthorized change of a Customer's Competitive Retailer (CR) when a Customer or a Premise is changed to a CR that is different from the Customer's expected CR of choice. An IAG is either reported as a gain by the ~~gaining~~ Gaining CR or a loss by the ~~losing~~ Losing CR.

~~**Losing Competitive Retailer**~~

~~CR identified in the initiating Decision who is to be removed as the REP of record upon the processing of a Mass Transition or Acquisition Transfer transaction.~~

~~**Target Effective Date**~~

~~Effective Date for the Mass Transition or Acquisition Transfer of ESI IDs identified in the Mass Transition or Acquisition Transfer Decision. This date may be modified by agreement among Market Participants based on the volume of transitioning ESI IDs and the TDSP's capacity to read meters and process transactions involving manual intervention.~~

5.3 Ad Hoc Retail Market Conference Calls

Market Participants may request an ad hoc retail market conference call by contacting the chair and/or vice-chair of the Retail Market Subcommittee (RMS). RMS leadership will contact ERCOT Client Services who will announce the call via a ~~market~~ Market Notice to the Retail Market Call (RMC) e-mail distribution list. Market Participants interested in receiving ad hoc retail market conference call announcements should subscribe to the RMC distribution list located on the ERCOT website. Topics of discussion for the ad hoc call may include but are not limited to:

(a) Transaction and system processing updates (i.e., processing statistics; slow, late or large volumes);

(b) Outage Notifications (i.e., planned/unplanned system Outages or maintenance updates); and

(c) Any issues affecting more than one Competitive Retailer (CR) or the entire market (i.e., re-bill efforts, synchronization).

7.3 Inadvertent Gain/Loss Process

(1) An Inadvertent Gain/Loss (IAG) is defined in Section 2.1, Definitions.

(2) The IAG process shall be used in cases where a Competitive Retailer (CR) is serving a Customer without proper authorization pursuant to P.U.C. SUBST. R. 25.474, Selection of Retail Electric Provider. This Section provides guidelines for ensuring that inadvertently gained Electric Service Identifiers (ESI IDs) are returned to the ~~losing~~ Losing CR in a quick and efficient manner with minimal inconvenience to the Customer as required by P.U.C. SUBST. R. 25.495, Unauthorized Change of Retail Electric Provider.

(3) CRs shall submit IAGs to ERCOT as promptly as possible via the MarkeTrak tool.

7.3.2.1.2 Breach of Contract

(1) The IAG process shall not be used to resolve an issue in which an authorized enrollment causes a breach of contract (e.g., early termination fee) between the Customer and the ~~losing~~ Losing CR.

(2) The IAG process shall not be used to resolve an issue in which an authorized enrollment causes a breach of contract (e.g., non-payment) between the Customer and the ~~gaining~~ Gaining CR.

7.3.2.2 Prevention of Inadvertent Gains

(1) If the ~~gaining~~ Gaining CR determines that a potential inadvertent gain may be avoided by cancelling a pending switch or move in transaction prior to the scheduled date, the ~~gaining~~ Gaining CR shall cancel the transaction using the 814_08, Cancel Request.

7.3.2.4 Gaining CR System Processing Errors

(1) Should a CR experience a system processing issue resulting in inadvertently gaining greater than 100 ESI IDs, the ~~gaining~~ Gaining CR shall send a timely informational-only Market Notice to all impacted Market Participants, via the MarkeTrak escalation contacts, detailing the cause of the issue, and send immediately following the submission of the IAG MarkeTraks.

7.3.2.5 Resolution of IAGs

(1) If the Gaining CR determines that the gain was inadvertent, the CR shall promptly submit an *Inadvertent Gaining* issue in MarkeTrak. (See Section 7.2, Market Synchronization, for more information about MarkeTrak).

(2) The Gaining CR shall not submit a Move-Out Request or a Disconnect for Non-Pay (DNP) on an ESI ID that was gained inadvertently.

(3) The Losing CR shall not submit an *Inadvertent Losing* issue in MarkeTrak until the Gaining CR's switch or move in transaction has completed.

(4) If the Gaining CR placed a switch hold on an ESI ID that was gained inadvertently via the 650_01, Service Order Request, the Gaining CR shall request the removal of all switch holds from the ESI ID via a 650_01 transaction before proceeding towards a resolution of the *Inadvertent Gaining* or *Inadvertent Losing* MarkeTrak issue. However, if a switch hold was placed on the ESI ID by the Transmission and/or Distribution Service Provider (TDSP) due to tampering, the Losing CR may request that the TDSP reinstate the tampering switch hold on the ESI ID in the *Inadvertent Gaining* or *Inadvertent Losing* MarkeTrak issue.

[RMGRR169: Replace paragraph (4) above with the following upon system implementation of NPRR1095:]

(4) If the Gaining CR placed a switch hold on an ESI ID that was gained ~~in error~~inadvertently via the 650_01, Service Order Request, the Gaining CR shall request the removal of all switch holds from the ESI ID via a 650_01 transaction before proceeding towards a resolution of the *Inadvertent Gaining* or *Inadvertent Losing* MarkeTrak issue. However, if a switch hold was placed on the ESI ID by the Transmission and/or Distribution Service Provider (TDSP) due to tampering, the Losing CR may request that the TDSP reinstate the tampering switch hold on the ESI ID.

(5) After the Losing CR regains the ESI ID, the TDSP will reinstate any critical care designations that have not expired and were previously assigned to the Customer at the ESI ID and submit the 814_20, ESI ID Maintenance Request.

7.3.2.5.1 Reinstatement Date

(1) The ~~losing~~Losing CR and the ~~gaining~~ Gaining CR may work together to negotiate a reinstatement date for the ~~losing~~ Losing CR to take the ESI ID back and note that date in the MarkeTrak issue. However, the ~~losing~~ Losing CR shall ultimately determine the reinstatement date and note that date in the MarkeTrak issue.

(2) The reinstatement date shall be one day beyond the date of loss (date of loss is the date the Customer started with the ~~gaining~~ Gaining CR) or any subsequent date chosen by the ~~losing~~ Losing CR for which the ~~losing~~ Losing CR had authorization to serve the Customer, but no greater than ten days from the date the MarkeTrak issue was submitted. If the reinstatement date in the backdated move in is prior to or equal to the ~~gaining~~ Gaining CR's start date, ERCOT will reject the backdated move in and resolution of the inadvertent gain will be delayed.

(3) If the reinstatement process is delayed, the reinstatement date shall be no greater than ten days from the date the MarkeTrak issue was submitted.

(4) No later than 12 days after the submittal of the *Inadvertent Gaining* or *Inadvertent Losing* MarkeTrak issue, the ~~losing~~ Losing CR shall submit an 814_16, Move In Request, that is backdated by at least one Retail Business Day. The backdated move in shall use the date as populated within the "proposed regain date" field in MarkeTrak as the requested reinstatement date. The ~~losing~~ Losing CR shall verify that the backdated move in was successfully received and accepted by the TDSP and populate the BGN02 field from that transaction.

(5) If the move in has not been submitted within the required timeline, or the reinstatement date is different than the date noted in the MarkeTrak issue, refer to the escalation process in the MarkeTrak Users Guide.

(6) MarkeTrak issues where all parties have agreed and the MarkeTrak issue remains untouched for 20 days from the date the TDSP selects *Ready to Receive* will be auto closed in the system.

7.3.2.6 Valid Reject/Unexecutable Reasons

(1) The ~~losing~~ Losing CR may reject the return of an inadvertently gained ESI ID from the ~~gaining~~ Gaining CR for one of the following reasons only:

(a) A new transaction has completed in the market, including, but not limited to the following transactions:

(i) The 814_16, Move In Request; or

(ii) The 814_01, Switch Request.

(b) Duplicate *Inadvertent Gaining* issue in MarkeTrak for the same Customer on the same ESI ID.

(c) The IAG was inappropriately submitted as described in Section 7.3.2.1, Invalid Use of the IAG Process.

(2) The ~~gaining~~ Gaining CR may reject returning an inadvertently gained ESI ID to the Losing CR for one of the following reasons only:

(a) A new transaction has completed in the market, including, but not limited to the following transactions:

(i) The 814_16 transaction; or

(ii) The 814_01 transaction.

(b) Duplicate *Inadvertent Losing* issue in MarkeTrak for the same Customer on the same ESI ID;

(c) The Gaining CR has confirmed with the Customer that the Customer's CR of choice is the Gaining CR:

(i) Gaining CR has a valid enrollment with the same Customer and provides the Customer name, service address and meter number (if available) in the comments section of the MarkeTrak issue.

(d) In cases of Customer rescission, *Inadvertent Losing* MarkeTrak issue is rejected/unexecuted and a *Rescission* MarkeTrak issue is created.

7.3.2.7 Invalid Reject/Unexecutable Reasons

(1) The ~~losing~~ Losing CR shall not reject the return of an inadvertently gained ESI ID due to:

(a) Inability to contact the Customer;

(b) Past due balances or credit history;

(c) Customer no longer occupies the Premise in question;

(d) Contract expiration or termination;

(e) Pending TX SETs; or

(f) Losing CR serving the Premise under a Continuous Service Agreement (CSA).

7.3.2.8 Out-of-Sync Condition

(1) If the ~~losing~~Losing CR does not have a record of ever serving the ESI ID involved in the *Inadvertent Gaining* MarkeTrak issue, the ~~losing~~ Losing CR shall update the MarkeTrak issue with this information. ERCOT and the ~~losing~~ Losing CR will work together to resolve the out-of-sync issue. TDSP corrections necessary to reestablish the ESI ID with the ~~losing~~ Losing CR may result in a TDSP invoice for a minimum of a one day charge which includes any applicable TDSP service charges according to the TDSP tariffs. For system logic rules, see Section 11, Solution to Stacking.

7.3.2.9 No Losing Competitive Retailer of Record

(1) If it is determined that the ~~losing~~ Losing CR is no longer active in the market, then it is recommended that the ~~gaining~~ Gaining CR make reasonable attempts to contact the Customer to resolve the issue and request that ERCOT close the MarkeTrak issue. If the ~~gaining~~ Gaining CR is unable to contact the Customer, they may consider following the rules established in P.U.C. SUBST. R. 25.488, Procedures for a Premise with No Service Agreement.

7.3.3 Charges Associated with Returning the Customer

(1) The affected CRs and TDSP shall take all actions necessary to correctly bill all charges, so that the end result is that the CR that served the ESI ID without proper authorization shall pay all transmission, distribution and discretionary charges associated with returning the ESI ID to the ~~losing~~ Losing CR, or CR of choice in the case of a move in. Each CR shall be responsible for all non-by-passable TDSP charges and wholesale consumption costs for the periods that the CR bills the Customer.

(2) If the ~~gaining~~ Gaining CR sends a move out or DNP (in violation of Section 7.3.2.5, Resolution of IAGs), and in order for the TDSP to reverse fees associated with the inadvertent gain, the ~~losing~~ Losing CR should file a MarkeTrak issue under the *Redirect Fees* subtype within three Retail Business Days following receipt of the 810_02, TDSP Invoice, containing discretionary fees as a result of the inadvertent gain. The ~~losing~~ Losing CR shall item link any existing related *Inadvertent Gaining* or *Inadvertent Losing* issues, if applicable. If the ~~gaining~~ Gaining CR agrees that an inadvertent gain has occurred, including agreement within a related inadvertent gain issue, then the ~~gaining~~ Gaining CR shall agree to the ~~losing~~ Losing CR's *Redirect Fees* MarkeTrak issue and shall not dispute any of the valid TDSP fees associated with returning the ESI ID to the ~~losing~~ Losing CR.

(3) The ~~losing~~ Losing CR shall not submit a priority 814_16, Move In Request, if the Customer currently has power.

7.3.4.2 Inadvertent Order is Pending

(1) If the inadvertent order is pending, TDSPs will respond with the following statement:

> *Since the inadvertent transaction is still pending, an attempt should be made by the ~~gaining~~ Gaining CR to cancel the transaction, provided that the ~~gaining~~ Gaining CR agrees to do so. If so, please submit an 814_08, Cancel Request, transaction prior to the date the inadvertent transaction is scheduled to complete. Otherwise, the inadvertent gain will follow the standard inadvertent process.*

7.3.4.4 Transmission and/or Distribution Service Provider Billing

(1) Once a backdated move in has been accepted by the TDSP, the TDSP shall invoice all transmission, distribution and discretionary charges associated with returning the Customer to the ~~losing~~ Losing CR, or CR of choice in the case of a move in, to the ~~gaining~~ Gaining CR. The TDSP shall be responsible for invoicing all non-bypassable TDSP charges to the CRs in accordance with the periods that they each served the Customer.

(2) Any disputes regarding TDSP charges shall be filed in accordance with Section 7.8, Formal Invoice Dispute Process for Competitive Retailers and Transmission and/or Distribution Service Providers.

[RMGRR169: Replace Section 7.3.4.4 above with the following upon system implementation of NPRR1095:]

7.3.4.2 Transmission and/or Distribution Service Provider Billing

(1) Once a backdated move in transaction has been accepted by the TDSP, the TDSP shall invoice all transmission, distribution and discretionary charges associated with returning the Customer to the Losing CR, or CR of choice in the case of a move in, to the Gaining CR. The TDSP shall be responsible for invoicing all non-bypassable TDSP charges to the CRs in accordance with the periods that they each served the Customer.

(2) Any disputes regarding TDSP charges shall be filed in accordance with Section 7.8, Formal Invoice Dispute Process for Competitive Retailers and Transmission and/or Distribution Service Providers.

7.3.5 Customer Rescission after Completion of a Switch Transaction

(1) The time period allowed for a Customer to rescind a switch transaction may extend beyond the completion date of a switch. If a Customer requests to cancel a switch for the purpose of rescission, the CR scheduled to gain the Premise shall attempt to cancel the transaction by following the steps outlined in Section 7.3.2.2, Prevention of Inadvertent Gains, regarding cancellation of the pending 814_01, Switch Request.

(a) If the TDSP is unable to cancel the switch, or the Customer waits until after the switch is complete to exercise the rescission, but the Customer is still rescinding the agreement within the timelines specified in P.U.C. SUBST. R. 25.474, Selection of Retail Electric Provider, the Gaining CR shall file a MarkeTrak issue, subtype *Customer Rescission*, to initiate reinstatement of the Customer to the previous CR.

(b) Upon receiving the Customer Rescission MarkeTrak issue, the Losing CR shall agree to the Customer Rescission MarkeTrak issue within two Business Days unless a valid reason for rejecting a rescission-based issue under Section 7.3.5.1, Additional Valid Reasons for Rejection of a Rescission-based Issue, is met.

[RMGRR169: Replace item (b) above with the following upon system implementation of NPRR1095:]

(b) Upon receiving the *Customer Rescission* MarkeTrak issue, the Losing CR shall agree to the Customer *Rescission* MarkeTrak issue within two Business Days.

(2) The TDSP shall not assess any fees related to Customer reinstatement in cases of a valid Customer rescission, provided the submit date of the MarkeTrak issue falls on or before the 25th day following the established First Available Switch Date (FASD) of the 814_03, Enrollment Notification Request, per the timeline specified in Protocol Section 15.1.1, Submission of a Switch Request. Once this time frame has expired, the Gaining CR will no longer be able to submit an issue under the subtype *Customer Rescission* and must use the *Inadvertent Gaining* subtype to return the Premise. The Gaining CR will incur all TDSP charges normally associated with the return of a Premise through that subtype.

[RMGRR~~169~~181: Replace paragraph (2) above with the following upon system implementation of NPRR1095:]

(2) The TDSP shall not assess any fees related to Customer reinstatement in cases of a valid Customer rescission, provided the submit date of the MarkeTrak issue falls on or before the 15th day following the established First Available Switch Date (FASD) of the 814_03, Enrollment Notification Request, per the timeline specified in Protocol Section 15.1.1, Submission of a Switch Request. Once this time frame has expired, the Gaining CR will no longer be able to submit an issue under the subtype Customer Rescission and must use the Inadvertent Gaining subtype to return the Premise. The Gaining CR will incur all TDSP charges normally associated with the return of a Premise through that subtype.

(3) Within two Business Days of the TDSP updating the *Customer Rescission* MarkeTrak issue status to *Ready to Receive*, the Losing CR shall submit the backdated 814_16, Move In Request, to reinstate the Customer for one day beyond the original date of loss. The option to reinstate the Customer for any date beyond that as outlined in Section 7.3.2.5.1, Reinstatement Date, is not applicable for rescissions received within the timelines specified in this scenario.

[RMGRR169: Replace paragraph (3) above with the following upon system implementation of NPRR1095:]

(3) Within two Business Days of CR agreement to the *Customer Rescission* MarkeTrak issue, the Losing CR shall submit the backdated 814_16, Move In Request, with the Customer Rescission indicator "CR" found in the BGN07 field, to reinstate the Customer for one day beyond the original date of loss. The option to reinstate the Customer for any date beyond that as outlined in Section 7.3.2.5.1, Reinstatement Date, is not applicable for rescissions received within the timelines specified in this scenario.

(4) The rules and guidelines set forth in previous sections regarding valid/invalid reject reasons, back-dated transactions over 150 days, pending order notification and third party transactions/leapfrog scenarios shall apply to rescission-based reinstatement.

(5) Only those enrollments initiated by an 814_01 transaction, and eligible for Customer rescission as defined in P.U.C. SUBST. R. 25.474, may be returned through the process outlined in this Section. Only the Gaining CR may initiate the process of returning the Customer to the Losing CR by filing a MarkeTrak issue upon being contacted by the Customer exercising rescission. If a Gaining CR attempts to submit a *Customer Rescission* issue in MarkeTrak only to discover an *Inadvertent Losing* issue has been submitted by the Losing CR for the same transaction, the Gaining CR shall mark the *Inadvertent Losing* issue unexecutable and proceed with submission of a new issue under the *Customer Rescission* subtype.

7.3.5.1 Additional Valid Reasons for Rejection of a Rescission-based Issue

(1) The TDSP may return an issue to the submitting CR due to the ~~gaining~~ Gaining CR requesting, and the TDSP completing, a move out transaction for the inadvertently gained ESI ID.

[RMGRR169: Delete Section 7.3.5.1 above upon system implementation of NPRR1095.]

7.10.4 Addition or Removal of Switch Hold by Retail Electric Provider of Record Request for 650 Transactions During Extended Unplanned System Outage Affecting the REP and/or TDSP

(1) In the event that an extended unplanned system outage prevents sending/receiving 650 TX SETs, the market may decide via an ad hoc retail market conference call, as described in Section 7.10, Emergency Operating Procedures for Extended Unplanned System Outages, that a manual workaround process to add or remove switch holds may be used.

(a) For a REP system issue, the REP will need to contact TDSPs to arrange for use of an agreed upon workaround.

(b) For a TDSP system issue, the TDSP is responsible for sending a ~~market~~ Market ~~notice~~Notice and coordinating with ERCOT to facilitate a retail market conference call as described in Section 7.10.

7.11.1 Transition Process of Competitive Retailer's Electric Service Identifiers to Provider of Last Resort or Designated Competitive Retailer Pursuant to P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR), or CR Voluntarily Leaving the Market

~~(1) This Section 7.11.1 outlines a transition process that can be used when such circumstances exist pursuant to P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR),~~

~~referred to herein as a "Mass Transition," and may include ESI IDs that are transferred to a designated CR as a result of an acquisition pursuant to P.U.C. SUBST. R. 25.493, Acquisition and Transfer of Customers from one Retail Electric Provider to Another.~~

(~~2~~1) Each opt-in Municipally Owned Utility (MOU) or opt-in Electric Cooperative (EC) without an affiliated POLR that has not delegated authority to designate POLRs to the Public Utility Commission of Texas (PUCT), as applicable to opt-in ECs, must provide its initial POLR allocation methodology to ERCOT no later than 30 days prior to the Customer Choice opt-in date using Section 9, Appendices, Appendix J7, Mass Transition Allocation Methodology. Should the opt-in MOU or opt-in EC determine the allocation methodology must be changed at any time, such updates must be provided to ERCOT no later than 30 days prior to its Mass Transition ~~effective~~ Effective ~~date~~ Date or at a time prior to the initiation of a Mass Transition as defined in Section 7.11.1.1, Mass Transition Initiation. All updates to the allocation methodology must be provided using Appendix J7. Confirmation of all allocation methodologies must be submitted to ERCOT prior to January 1st of each odd numbered year using Section 9, Appendix J8, Attestation to Confirm Mass Transition Allocation Methodology.

(~~3~~2) Market Participants that wish to transfer Customers for reasons other than P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR), should contact ERCOT Client Relations and the PUCT Staff.

(~~4~~3) Per Protocol Section 16.1.1, Re-Registration as a Market Participant, any Market Participant that has had its Customers dropped via the Mass Transition process must provide to ERCOT a new Data Universal Numbering System (DUNS) Number (DUNS #) to re-register as a Market Participant with ERCOT.

(~~5~~4) For the purpose of a Mass Transition and the associated timeline, the following definitions shall apply:

(a) Notification Date - Date on which ERCOT sends the initial Mass Transition Market Notice to affected parties informing them that a Mass Transition will occur as a result of a Market Participant default, also known as the pre-Launch stage in the process.

(b) Calendar Day 0 - Date that ERCOT sends 814_03, Enrollment Notification Request. This can be on the Notification Date.

(c) Mass Transition Date - Scheduled Meter Read Date (SMRD) will be equal to Calendar Day 0 plus two days and will be the date requested in the 814_03 transaction from ERCOT to the TDSP. POLRs will be responsible for ESI IDs no earlier than the Mass Transition Date.

(~~6~~5) The processes described in this Section presume that a Mass Transition ~~decision~~ Decision to transfer the ESI IDs has already been made by ERCOT as a result of a Market Participant's default of the Standard Form Market Participant Agreement with ERCOT.

(~~7~~6) ERCOT may coordinate periodic testing with Market Participants of Mass Transition processes as defined in this Section and Section 11, Solution to Stacking.

7.11.1.4.1.2 ERCOT Pre-Launch Responsibilities in a Mass Transition

(1) Identify the defaulting CR;

(2) Identify the appropriate POLR(s) or designated CR;

(3) Identify all of the affected TDSPs and CRs (current, CSA, and pending new CR);

(4) Determine the ESI IDs by designated POLR class associated to the Mass Transition and notify the affected parties according to the following:

(a) If all ESI IDs associated with the Mass Transition will only be allocated among Volunteer Retail Electric Providers (VREPs), then ERCOT will only need to include affected parties in the Mass Transition project; or

(b) If all ESI IDs associated with the Mass Transition will be allocated among Large Service Providers (LSPs) and VREPs, then ERCOT will include affected parties in the Mass Transition project.

(5) Determine the Mass Transition ~~launch~~Launch timeline;

(6) Determine the Mass Transition completion date to be no more than five days after ERCOT generates and the TDSP receives the 814_03, Enrollment Notification Request, with the Mass Transition indicator, for all affected ESI IDs;

(7) Designate the ERCOT Mass Transition project lead;

(8) Schedule and conduct Mass Transition project coordination calls with affected parties;

(9) Complete and disseminate required Mass Transition Market Notices;

(10) Delete or disable CSAs to prevent the Losing CR from becoming the Retail Electric Provider (REP) responsible for an ESI ID (REP of record) on an ongoing basis after the Mass Transition has begun;

(11) Identify Pending TX SETs associated with those affected ESI IDs;

(12) Send a list of ESI IDs targeted to the POLRs or designated CRs where they are expected to become REP of record and to the affected TDSP(s) (see Section 9, Appendices, Appendix F4, ERCOT Template - Electric Service Identifiers for Gaining Competitive Retailer/Transmission and/or Distribution Service Provider Use);

(13) Assign ESI IDs to the POLR(s) as directed by ALA and the POLR rule;

(14) Provide a list of ESI IDs to any CR (both POLR and non-POLR) of any Pending switch transactions with a scheduled date greater than two Business Days after the Mass Transition Date (including in-review and scheduled). See Section 9, Appendices, Appendix F5, ERCOT Template – Electric Service Identifiers for New Competitive Retailer with Pending Transactions; and

(15) Manage the POLR DUNS # list according to the registration by the POLR Entities.

7.11.1.4.2.2 ERCOT Responsibilities During the Mass Transition

(1) Schedule and conduct initial and periodic Mass Transition project coordination calls, as needed;

(2) Complete and disseminate Mass Transition Market Notices as needed;

(3) Coordinate dissemination of mandated PUCT communications to impacted Customers;

(4) Provide Customer billing contact information in accordance with Section 7.11.3.3, Submission of Customer Billing Contact Information During a Mass Transition Event;

(5) Create and submit the 814_03, Enrollment Notification Request, with the Mass Transition indicator for the affected ESI IDs;

(6) Identify and monitor all transitioned ESI IDs to ensure that the first switch following a Mass Transition (if received within 60 days of the effective date provided in the 814_03 transaction with the Mass Transition indicator) is forwarded to the TDSP with a requested Mass Transition ~~effective~~ Effective ~~date~~ Date equal to the First Available Switch Date (FASD). Identification of the transitioned ESI ID shall terminate either upon the first completed switch, move in, move out, or at the end of the 60 day period, whichever occurs first;

[RMGRR168: Replace paragraph (6) above with the following upon system implementation:]

(6) Identify and monitor all transitioned ESI IDs to ensure that the first 814_01, Switch Request, transaction following a Mass Transition (if received within 60 days of the Mass Transition ~~effective~~ Effective ~~date~~ Date provided in the 814_03 transaction with the Mass Transition indicator) is forwarded by ERCOT with the CR's requested date to the TDSP for scheduling according to the TDSP tariff timelines. Identification of the transitioned ESI ID by ERCOT shall terminate either upon the first completed switch, move in, move out, or at the end of the 60 day period, whichever occurs first;

(7) Once ERCOT has received the 814_04, Enrollment Notification Response, from TDSPs on the affected ESI IDs, forward the 814_14, Drop Enrollment Request, to the POLRs or designated CRs, and forward the 814_11, Drop Response, to the defaulting CR;