submit Resource-specific telemetry indicating the Resource's ability to provide Ancillary Service in Real-Time.

(3) QSEs representing Load Resources providing Ancillary Service via high-set under-frequency relays may self-provide high-set under-frequency relay-controlled RRS and ECRS; the amount of self-provision shall be limited based on the QSE's Day-Ahead Market (DAM) Ancillary Service awards and trades.

(4) A previously Off-Line Generation Resource in startup mode due to a manual deployment of Non-Spin by ERCOT will continue to be eligible for Non-Spin. The eligible capacity shall be based on the telemetered HSL of the Resource minus its Base Point Dispatch Instruction by SCED interval.

(5) A Quick Start Generation Resource (QSGR) in startup mode due to an ERCOT Dispatch Instruction will continue to be eligible for ECRS and Non-Spin. The eligible capacity shall be based on the telemetered HSL of the Resource minus its Base Point Dispatch Instruction by Security-Constrained Economic Dispatch (SCED) interval.

(6) ERCOT may manually reduce the amount of Ancillary Service eligible to be awarded to a Resource that, if deployed, could violate a transmission constraint. ERCOT shall notify the Resource's QSE in Real-Time of any Ancillary Service capability that has been derated by ERCOT, including the Resource's new Ancillary Service limit in MWs. Should the deration impact payments the QSE would have received under Section 6.7.5.1, Real-Time Ancillary Service Imbalance, the QSE will be eligible for consideration of a payment under Section 6.7.5.7, Real-Time Derated Ancillary Service Capability Payment.

(7) Sixty days after the applicable Operating Day, ERCOT shall post to the ERCOT website the instances of ERCOT Operator reduction of Ancillary Services capability, including the name of the Resource, the type and reduced MW by Ancillary Service, and the reason for the reduction.

(8) Ancillary Service awards and Real-Time Market Clearing Prices for Capacity (MCPCs) are immediately binding upon the completion of a SCED run.

6.5.7.3 Security Constrained Economic Dispatch

Commented [PC5]: Please note NPRR1188 also proposes revisions to this section.

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

telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP.

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

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

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

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

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

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

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

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

(b) DSRs with Energy Offer Curves

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

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

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

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

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

(d) IRRs

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

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

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

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

(e) RUC-committed Resources

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

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

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

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

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

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

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

MW	Price (per MWh)

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

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

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

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

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

(8) If a Controllable Load Resource telemeters a status of OUTL, it is not considered as dispatchable capacity by SCED. A QSE may use this function to inform ERCOT of instances when the Controllable Load Resource is unable to follow SCED Dispatch Instructions. Under all telemetered statuses including OUTL, the remaining telemetry

quantities submitted by the QSE shall represent the operating conditions of the Controllable Load Resource that can be verified by ERCOT. A QSE representing a Controllable Load Resource with a telemetered status of OUTL is still obligated to provide any applicable Ancillary Service Resource Responsibilities previously awarded to that Controllable Load Resource. This paragraph does not apply to ESRs.

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

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

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

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

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

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

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

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

the summary to Market Participants on the MIS Secure Area and to the Independent Market Monitor (IMM).

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

(12) For each SCED process, ERCOT shall calculate a Real-Time On-Line Reserve Price Adder and a Real-Time Off-Line Reserve Price Adder based on the On-Line and Off-Line available reserves in the ERCOT System and the Operating Reserve Demand Curve (ORDC). The Real-Time Off-Line available reserves shall be administratively set to zero when the SCED snapshot of the Physical Responsive Capability (PRC) is equal to or below the PRC MW at which Energy Emergency Alert (EEA) Level 1 is initiated. In addition, for each SCED process, ERCOT shall calculate a Real-Time On-Line Reliability Deployment Price Adder. The sum of the Real-Time Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder shall be averaged over the 15-minute Settlement Interval and added to the Real-Time LMPs to determine the Real-Time Settlement Point Prices. The price after the addition of the sum of the Real-Time On-Line Reliability Deployment Price Adder and the Real-Time On-Line Reserve Price Adder to LMPs approximates the pricing outcome of the impact to energy prices from reliability deployments and the Real-Time energy and Ancillary Service co-optimization since the Real-Time On-Line Reserve Price Adder captures the value of the opportunity cost of reserves based on the defined ORDC. An Ancillary Service imbalance Settlement shall be performed pursuant to Section 6.7.5, Real-Time Ancillary Service Imbalance Payment or Charge, to make Resources indifferent to the utilization of their capacity for energy or Ancillary Service reserves.

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

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

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

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

[NPRR930, NPRR1000, NPRR1010, NPRR1014, and NPRR1019: Replace applicable portions of Section 6.5.7.3 above with the following upon system implementation for NPRR930, NPRR1000, NPRR1014, or NPRR1019; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.3 Security Constrained Economic Dispatch

(1) The SCED process is designed to simultaneously manage energy, Ancillary Services, the system power balance and network congestion through Resource Base Points, Ancillary Service awards, and the calculation of LMPs and Real-Time MCPCs approximately every five minutes, or more frequently if necessary. The SCED process uses a two-step methodology that applies mitigation to offers for energy prospectively to resolve Non-Competitive Constraints for the current Operating Hour. The SCED process evaluates Energy Offer Curves, Energy Bid/Offer Curves, Ancillary Service Offers, Output Schedules and Real-Time Market (RTM) Energy Bids to determine Resource Dispatch Instructions and Ancillary Service awards by maximizing bid-based revenues minus offer-based costs, subject to power balance, Ancillary Service Demand Curves (ASDCs), and network constraints. The SCED process uses the Resource Status provided by SCADA telemetry under Section 6.5.5.2, Operational Data Requirements, and validated by the Real-Time Sequence, instead of the Resource Status provided by the COP. In addition, the SCED process accounts for each Energy Storage Resource's (ESR's) State of Charge (SOC) and SOC operating limits. This is to ensure that the SCED process will issue ESR Base Points and Ancillary Services that are feasible taking into account SCED duration requirements for Energy and

Ancillary Services and also that do not violate the ESR's MinSOC and MaxSOC limits.

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

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

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

(a) Non-IRRs without Energy Offer Curves

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

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

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

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

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

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

LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

(c) IRRs

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

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

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

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

(d) RUC-committed Resources

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

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

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

MW	Price (per MWh)

HSL (if more than highest MW in Energy Offer Curve)	Greater of $250 or price associated with the highest MW in QSE submitted Energy Offer Curve
Energy Offer Curve	Greater of $250 or the QSE submitted Energy Offer Curve
Zero	Greater of $250 or the first price point of the QSE submitted Energy Offer Curve

(iii) For each RUC-committed Resource during the time period stated in the Advance Action Notice (AAN) if any Resource received an Outage Schedule Adjustment, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	$4,500 or the effective Value of Lost Load (VOLL), whichever is less.
Zero	$4,500 or the effective VOLL, whichever is less.

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

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

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

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

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

(vi) For each RUC-committed Switchable Generation Resource (SWGR) that is not part of a Combined Cycle Train already operating in ERCOT, that has not submitted an Energy Offer Curve, and that has a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of the RUC instruction, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL	$4,500 or the effective Value of Lost Load (VOLL), whichever is less
Zero	$4,500 or the effective VOLL, whichever is less

(vii) For each RUC-committed SWGR that is not part of a Combined Cycle Train already operating in ERCOT, that has submitted an Energy Offer Curve, and that has a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of the RUC instruction, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL (if more than highest MW in Energy Offer Curve)	Greater of: $4,500 or the effective VOLL, whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve	Greater of: $4,500 or the effective VOLL, whichever is less; and the QSE-submitted Energy Offer Curve

Zero	Greater of: $4,500 or the effective $VOLL_2$ whichever is less; and the first price point of the QSE-submitted Energy Offer Curve

(viii) For each Combined Cycle Train configuration that includes at least one SWGR that is operating in a non-ERCOT Control Area as part of a configuration with a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of a RUC instruction requiring the switching of the SWGR into the ERCOT Control Area, if the QSE for the Combined Cycle Train has not submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration	$4,500 or the effective VOLL, whichever is less
Zero	$4,500 or the effective $VOLL_2$ whichever is less

(ix) For each Combined Cycle Train configuration that includes at least one SWGR that is operating in a non-ERCOT Control Area as part of a configuration with a COP Resource Status of EMRSWGR for the instructed Operating Hour at the time of a RUC instruction requiring the switching of the SWGR into the ERCOT Control Area, if the QSE for the Combined Cycle Train has submitted an Energy Offer Curve for the RUC-committed configuration, ERCOT shall create a proxy Energy Offer Curve as described below:

MW	Price (per MWh)
HSL of RUC-committed configuration (if more than highest MW in Energy Offer Curve)	Greater of: $4,500 or the effective $VOLL_2$ whichever is less; and the price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve for MW at and above HSL of QSE-committed configuration	Greater of: $4,500 or the effective $VOLL_2$ whichever is less; and the QSE-submitted Energy Offer Curve
HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve and price associated with highest MW in Energy Offer Curve is less than $4,500)	$4,500 or the effective VOLL, whichever is less

HSL of QSE-committed configuration (if more than highest MW in Energy Offer Curve)	Price associated with the highest MW in QSE-submitted Energy Offer Curve
Energy Offer Curve for MW at and below HSL of QSE-committed configuration	The QSE-submitted Energy Offer Curve
1 MW below lowest MW in Energy Offer Curve (if more than LSL)	-$249.99
LSL (if less than lowest MW in Energy Offer Curve)	-$250.00

(5) For use as SCED inputs for determining energy dispatch and Ancillary Service awards, ERCOT shall use the available Ancillary Service MW capacity of all Resources by creating a proxy Ancillary Service Offer for qualified Resources as follows:

(a) The proxy Ancillary Service Offer shall be a linked Ancillary Service Offer across all Ancillary Service products for which a Resource is qualified to provide. For Generation Resources, the proxy Ancillary Service Offer MW shall be equal to the Resource's telemetered HSL. For ESRs, the proxy Ancillary Service Offer MW shall be equal to the difference between the Resource's telemetered HSL and LSL. For Load Resources, the proxy Ancillary Service Offer MW shall be equal to the Resource's telemetered Maximum Power Consumption (MPC).

(b) For Resources that are not RUC-committed, the price in the proxy Ancillary Service Offer shall be set to:

(i) For Reg-Up and RRS, the maximum of:

(A) The proxy Ancillary Service Offer price floor for Reg-Up or RRS, respectively;

(B) The Resource's highest submitted Ancillary Service Offer price for Reg-Up or RRS, respectively;

(C) The Resource's highest Ancillary Service Offer price for ECRS (submitted or proxy); or

(D) The Resource's highest Ancillary Service Offer price for Non-Spin (submitted or proxy).

(ii) For ECRS, the maximum of:

(A) The proxy Ancillary Service Offer price floor for ECRS;

(B) The Resource's highest submitted Ancillary Service Offer price for ECRS; or

(C) The Resource's highest Ancillary Service Offer price for Non-Spin (submitted or proxy).

(iii) For Non-Spin, the maximum of:

(A) The proxy Ancillary Service Offer price floor for Non-Spin; or

(B) The Resource's highest submitted Ancillary Service Offer price for Non-Spin.

(iv) For Reg-Down, the maximum of:

(A) The proxy Ancillary Service Offer price floor for Reg-Down; or

(B) The Resource's highest submitted Ancillary Service Offer price for Reg-Down.

(c) ERCOT systems shall be designed to allow for proxy Ancillary Service Offer price floors to differ when the same Ancillary Service product can be provided by either On-Line or Off-Line Resources, and/or an Ancillary Service product has sub-types.

(d) Proxy Ancillary Service Offer price floors shall be approved by TAC and posted on the ERCOT website.

(e) For RUC-committed Resources:

(i) If a RUC-committed Resource does not have an Ancillary Service Offer for an Ancillary Service product that the Resource is qualified to provide, ERCOT shall create an Ancillary Service Offer for that Ancillary Service product at a value of $250/MWh for the full operating range of the Resource up to its telemetered HSL.

(ii) For each Ancillary Service product for which a RUC-committed Resource has an Ancillary Service Offer, the Ancillary Service Offer used by SCED for that Ancillary Service product across the full operating range of the Resource up to its telemetered HSL shall be the maximum of:

(A) The Resource's highest submitted Ancillary Service Offer price; or

(B) $250/MWh.

(6) For use as SCED inputs for determining energy Dispatch and Ancillary Service awards, ERCOT shall use the available capacity of all On-Line ESRs by creating proxy Energy Bid/Offer Curves for certain Resources as follows:

(a) For each ESR for which its QSE has submitted an Energy Bid/Offer Curve that does not cover the full offer range (LSL to HSL) of the Resource's available capacity, ERCOT shall create a proxy Energy Bid/Offer Curve that extends the submitted Energy Bid/Offer Curve to use the entire available capacity of the Resource above the highest MW point on the Energy Bid/Offer Curve to the Resource's HSL and from the lowest MW point on the Energy Bid/Offer Curve to LSL, using these prices for the corresponding MW segments:

Scenario	MW Segment	Price (per MWh)
HSL MW and the highest MW point on the Energy Bid/Offer are both greater than or equal to zero, and, HSL is greater than the highest MW in submitted Energy Bid/Offer Curve	From highest MW point on submitted Energy Bid/Offer Curve to HSL MW	RTSWCAP
HSL MW is greater than or equal to zero, and, the highest MW point on the Energy Bid/Offer is less than zero	From highest MW point on submitted Energy Bid/Offer Curve to 0 MW From 0 MW to HSL	Price associated with the highest MW in submitted Energy Bid/Offer Curve RTSWCAP
HSL is less than zero and is also greater than the highest MW in submitted Energy Bid/Offer Curve	From highest MW point on submitted Energy Bid/Offer Curve to HSL MW	Price associated with the highest MW in submitted Energy Bid/Offer Curve
Energy Bid/Offer Curve		Energy Bid/Offer Curve
LSL MW and the lowest MW point on the Energy Bid/Offer Curve are both greater than or equal to zero, and, LSL is less than the lowest MW in submitted Energy Bid/Offer Curve	From LSL to lowest MW point on submitted Energy Bid/Offer Curve	Price associated with the lowest MW in submitted Energy Bid/Offer Curve
LSL MW is less than zero, and, the lowest MW point on the Energy Bid/Offer Curve is greater than zero	From LSL to 0 MW From 0 MW to lowest MW point on submitted Energy Bid/Offer Curve	-$250.00 Price associated with the lowest MW in submitted Energy Bid/Offer Curve
LSL and the lowest MW point on the Energy Bid/Offer Curve are both less than or equal to zero, and, LSL is less than the lowest MW point on the Energy Bid/Offer Curve	From LSL to lowest MW point on submitted Energy Bid/Offer Curve	-$250.00

(b) At the time of SCED execution, if a valid Energy Bid/Offer Curve or Output Schedule does not exist for an ESR that has a status of On-Line, then ERCOT

shall notify the QSE and create a proxy Energy Bid/Offer Curve priced at -$250/MWh for the MW portion of the curve less than zero MW, and priced at the RTSWCAP for the MW portion of the curve greater than zero MW.

(c) At the time of SCED execution, if a QSE representing an ESR has submitted an Output Schedule instead of an Energy Bid/Offer Curve, ERCOT shall create a proxy Energy Bid/Offer Curve priced at -$250/MWh for the MW portion of the curve from its LSL to the MW amount on the Output Schedule, and priced at the RTSWCAP for the MW portion of the curve from the MW amount on the Output Schedule to its HSL.

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

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

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

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

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

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

(12) SCED will enforce Resource-specific Ancillary Service constraints to ensure that Ancillary Service awards are aligned with a Resource's qualifications and telemetered Ancillary Service capabilities.

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

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

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

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

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

(ii) Use Energy Bid/Offer Curves for all On-Line ESRs, whether submitted by QSEs or created by ERCOT. Each Energy Bid/Offer Curve must be bounded at the lesser of the Reference LMP (from Step 1) or the appropriate Mitigated Offer Floor. The offer portion of each Energy Bid/Offer Curve subject to mitigation under the criteria described in Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, must be capped at the greater of the Reference LMP (from Step 1) at the Resource Node plus a variable not to exceed

0.01 multiplied by the value of the Resource's MOC curve at the LSL or the appropriate MOC;

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

(iv) Observe all Competitive and Non-Competitive Constraints; and

(v) Use Ancillary Service Offers to determine Ancillary Service awards.

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

(d) The System Lambda used to determine LMPs from SCED Step 2 shall be capped at the effective VOLL.

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

Real-Time Reliability Deployment Price Adders, Hub LMPs and Load Zone LMPs on the ERCOT website pursuant to Section 6.3.2, Activities for Real-Time Operations.

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

(17) The QSE representing an ESR may withdraw energy from the ERCOT System only when dispatched by SCED to do so. An ESR may telemeter a status of OUT only if the ESR is in Outage status.

6.5.7.5 Ancillary Services Capacity Monitor

Commented [PC6]: Please note NPRR1188 also proposes 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:

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

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.

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

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

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

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

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

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

PRC_6 = 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 not carrying Ancillary Service Resource Responsibility

PRC_7 = $\sum_{i=online\ FFR\ resource}^{All\ online\ FFR\ resources}$ (Capacity from Resources capable of providing FFR)$_i$

PRC_8 = $\sum_{i=online\ ESR}^{All\ online\ ESR}$ (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 carrying Ancillary Service Resource Responsibility
PRC_6	MW	Capacity from Controllable Load Resources active in SCED 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, and NPRR1029: 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:]

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; ~~and~~.

(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:

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

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.

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

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

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

$PRC_4 =$	$\sum_{i=online\ load\ resource}^{All\ online\ load\ resources}$	(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)$_i$
$PRC_5 =$	$\sum_{i=online\ load\ resource}^{All\ online\ load\ resources}$	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 with an Ancillary Service Resource award
$PRC_6 =$	$\sum_{i=online\ load\ resource}^{All\ online\ load\ resources}$	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 without an Ancillary Service Resource award
$PRC_7 =$	$\sum_{i=online\ FFR\ resource}^{All\ online\ FFR\ resources}$	(Capacity from Resources capable of providing FFR)$_i$
$PRC_8 =$	$\sum_{i=online\ ESR}^{All\ online\ ESR}$	(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

$PRC_9 = \sum_{i=online}^{All\ online\ DC\text{-}Coupled\ Resources} ESR$ (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 with an Ancillary Service Resource award
PRC_6	MW	Capacity from Controllable Load Resources active in SCED 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_T		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.

ERCOT Impact Analysis Report

NPRR Number	1204	NPRR Title	Considerations of State of Charge with Real-Time Co-Optimization Implementation
Impact Analysis Date		October 10, 2023	
Estimated Cost/Budgetary Impact		Between $750K and $1M	
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)		Implementation Labor: 23% ERCOT; 77% Vendor Ongoing Requirements: No impacts to ERCOT staffing.	
ERCOT Computer System Impacts		The following ERCOT systems would be impacted: • Market Operation Systems 96% • Energy Management Systems 4%	
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
The budgetary and system impacts reflected above are captured in PR447, Real-Time Co-optimization.

Board Report

NOGRR Number	257	NOGRR Title	Removal of Redundant ERS Reporting Requirement
Date of Decision		December 19, 2023	
Action		Recommended Approval	
Timeline		Normal	
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		9.1.2, Compliance with Valid Dispatch Instructions	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Nodal Operating Guide Revision Request (NOGRR) resolves a conflict in Emergency Response Service (ERS) event reporting timelines between the Operating Guide and Protocols by striking the 90-day event reporting requirement in the Operating Guide.	
Reason for Revision		[X] Addresses current operational issues. [ ] Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). [X] Market efficiencies or enhancements [ ] Administrative [ ] Regulatory requirements [ ] Other: (explain) *(please select all that apply)*	
Business Case		This NOGRR removes a vague reference to ERS reporting in the Operating Guide, as a more detailed reporting requirement already exists within Protocol Section 8.1.3.1.4, Event Performance Criteria for Emergency Response Service Resources.	
ROS Decision		On 9/7/23, ROS voted unanimously to recommend approval of NOGRR257 as submitted. All Market Segments participated in the vote.	

Board Report

	On 10/5/23, ROS voted unanimously to endorse and forward to TAC the 9/7/23 ROS Report and 8/21/23 Impact Analysis for NOGRR257. All Market Segments participated in the vote.
Summary of ROS Discussion	On 9/7/23, ERCOT Staff provided an overview of NOGRR257 and the existing reports already codified within Protocols. On 10/5/23, there was no discussion.
TAC Decision	On 10/24/23, TAC voted unanimously to recommend approval of NOGRR257 as recommended by ROS in the 10/5/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for NOGRR257.
ERCOT Board Decision	On 12/19/23, the ERCOT Board voted unanimously to recommend approval of NOGRR257 as recommended by TAC in the 10/24/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on NOGRR257.
ERCOT Opinion	ERCOT supports approval of NOGRR257.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NOGRR257 and believes the market impact for NOGRR257 is the removal of duplicative reporting requirements within the Nodal Operating Guide as more detailed reporting already exists within Protocols.

Sponsor	
Name	Thelma Garza
E-mail Address	thelma.garza@ercot.com
Company	ERCOT
Phone Number	512-248-3936
Cell Number	
Market Segment	Not applicable

Board Report

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

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

9.1.2 Compliance with Valid Dispatch Instructions

(1) ERCOT shall produce monthly reports detailing Resource-specific Regulation Service and energy deployment performance, including Load Resources, based on the criteria described in Protocol Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance.

(2) ERCOT shall produce a report for any system-wide deployment of Load Resources ~~and/or ERS,~~ on an event basis, within 90 days after the event occurs and shall post it to the MIS Secure Area.

ERCOT Impact Analysis Report

NOGRR Number	257	NOGRR Title	Removal of Redundant ERS Reporting Requirement
Impact Analysis Date		August 21, 2023	
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		No impacts to ERCOT business processes.	
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

PGRR Number	110	PGRR Title	Revision to Accommodate Steady-State Node-Breaker Modeling
Date of Decision		December 19, 2023	
Action		Recommended Approval	
Timeline		Normal	
Proposed Effective Date		First of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not Applicable	
Planning Guide Sections Requiring Revision		6.1, Steady-State Model Development	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This Planning Guide Revision Request (PGRR) removes paragraph (2)(a) of Section 6.1 to accommodate the release of steady-state planning models in node-breaker format pursuant to System Change Request (SCR) 789, Update NMMS Topology Processor to PSSE 34 Capability.	
Reason for Revision		☐ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☒ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*	
Business Case		With the implementation of SCR789, the Network Operations Model will no longer be converted from a node-breaker model to a bus-branch model for planning purposes. Therefore, the differences due	

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	to the conversion from node-breaker to bus-branch will be removed from the steady-state models.
ROS Decision	On 8/3/23, ROS voted unanimously to table PGRR110 and refer the issue to the Steady State Working Group (SSWG). All Market Segments participated in the vote. On 9/7/23, ROS voted unanimously to recommend approval of PGRR110 as submitted. All Market Segments participated in the vote. On 10/5/23, ROS voted unanimously to endorse and forward to TAC the 9/7/23 ROS Report and 7/19/23 Impact Analysis for PGRR110. All Market Segments participated in the vote.
Summary of ROS Discussion	On 8/3/23, ERCOT Staff reviewed PGRR110 and referenced previous, ongoing SSWG discussion. On 9/7/23, Market Participants referenced SSWG approval of PGRR110. On 10/5/23, Market Participants reviewed the 7/19/23 Impact Analysis.
TAC Decision	On 10/24/23, TAC voted unanimously to recommend approval of PGRR110 as recommended by ROS in the 10/5/23 ROS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 10/24/23, TAC reviewed the ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for PGRR110.
ERCOT Board Decision	On 12/19/23, the ERCOT Board voted unanimously to recommend approval of PGRR110 as recommended by TAC in the 10/24/23 TAC Report.

Opinions	
Credit Review	Not applicable
Independent Market Monitor Opinion	IMM has no opinion on PGRR110.
ERCOT Opinion	ERCOT supports approval of PGRR110.
ERCOT Market Impact Statement	ERCOT Staff has reviewed PGRR110 and believes that it provides a positive market impact by creating market efficiencies and enhancements through the removal of paragraph (2)(a) of Section

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	6.1 in order to accommodate the release of steady-state planning models in node-breaker format pursuant to SCR789.

Sponsor	
Name	Eric Meier
E-mail Address	Eric.Meier@ercot.com
Company	ERCOT
Phone Number	512-248-6770
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**
None	

Market Rules Notes

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

- PGRR111, Related to NPRR1191, Registration, Interconnection, and Operation of Customers with Large Loads; Information Required of Customers with Loads 25 MW or Greater
  - Section 6.1

Proposed Guide Language Revision

6.1 Steady-State Model Development

Commented [JT1]: Please note PGRR111 also proposes revisions to this section.

(1) To adequately simulate steady-state system conditions, it is necessary to establish and maintain steady-state data and simulation ready study cases in accordance with the ERCOT Steady State Working Group Procedure Manual. These case models, known as

steady-state base cases, shall contain appropriate equipment characteristics and system data, and shall represent projected system conditions that provide a starting point for each required season and year.

(a) The Annual Planning Model base cases, which represent the annual peak load conditions, as prescribed in Protocol Section 3.10.2, Annual Planning Model, shall be developed annually, updated on a biannual basis, and may be updated as needed on an interim basis. Each Annual Planning Model base case, biannual updates, and off-cycle updates shall be posted on the Market Information System (MIS) Secure Area to ensure availability of the most accurate steady-state base cases.

(b) Additional steady-state base cases, such as seasonal base cases, shall also be developed annually, updated on a biannual basis, and may also be updated as needed on an interim basis. These derivative base cases, biannual updates, and off-cycle updates shall be posted on MIS Secure Area to ensure availability of the most accurate steady-state base cases.

(c) Off-cycle updates not associated with the biannual update shall be posted in a timely manner and include:

(i) Corrections to significant errors discovered in modeling or major changes in operation configuration that affect the steady-state base cases; or

(ii) A significant change in the scope or timing of a transmission project or the development of a new transmission project that impacts either of the next two summer base cases.

(d) Off-cycle updates that are posted as described in paragraphs (1)(a) through (c) above shall be in the form of a Power System Simulator for Engineering (PSS/E) formatted incremental change file.

(e) All steady-state base cases and incremental change files on the MIS Secure Area shall be available for use by Market Participants.

(f) The ERCOT Steady State Working Group Procedure Manual describes each base case that is required to be built. The schedule for posting all steady-state base cases shall be made available on the MIS Secure Area.

(2) Transmission Service Providers (TSPs) and ERCOT shall develop the steady-state base cases. The steady-state base cases are derived from the Network Operations Model to ensure consistency of key characteristics, including Ratings, impedance and connectivity for Transmission Facilities that are common between the Network Operations Model and each steady-state base case. Minor differences between the models will occur for several reasons. For example:

~~(a) The Network Operations Model is converted from a "breaker, switch, and AC bugment" convention to an equivalent steady-state base case "bus and branch"~~

~~convention. This conversion reduces the number of breakers/switches that may be included in the steady-state base case model and may combine buses separated by breakers/switches in the Network Operations Model.~~

(~~b~~a) Additional detailed modeling may be added to the converted Network Operations Model for planning purposes.

(~~eb~~) Future projects are added to the converted Network Operations Model that do not exist in the Network Operations Model past the model build date used to extract a snapshot from the Network Operations Model.

(3) Using the Network Model Management System (NMMS), ERCOT and TSPs shall create ~~steady-~~steady-state models that represent current and planned system conditions from the following data elements:

(a) Each TSP, or its Designated Agent, shall provide its respective transmission network steady-state model data, including load data.

(b) Each TSP, or its Designated Agent, shall not include the impact of energy sources connected to the Distribution System that are registered with ERCOT and required to provide telemetry including, but not limited to, Distribution Generation Resources (DGRs), Distribution Energy Storage Resources (DESRs), or Settlement Only Distribution Generators (SODGs) in its submitted Load data as negative loads or as embedded reductions in the submitted load forecast.

(c) Each TSP, or its Designated Agent, shall include the impact of energy sources connected to the Distribution System that are not registered with ERCOT in its submitted Load data. The methodology used shall be consistent across all TSPs and described in the ERCOT Steady State Working Group Procedure Manual.

(d) ERCOT shall utilize the latest available Resource Entity and Private Use Network model data submitted to ERCOT by the Resource Entity and the Private Use Network owners through the Resource Registration process for Resource Entities.

(e) ERCOT shall utilize proposed Generation Resource model data provided by the Interconnecting Entity (IE) during the generation interconnection process in accordance with Section 5, Generator Interconnection or Modification.

(f) ERCOT shall determine the operating state of Generation Resources (MW, MVAr) using a security-constrained economic dispatch tool.

(g) ERCOT shall determine the import/export levels of asynchronous transmission interconnections based on historical data.

ERCOT Impact Analysis Report

PGRR Number	110	PGRR Title	Revision to Accommodate Steady-State Node-Breaker Modeling
Impact Analysis Date		July 19, 2023	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Planning Guide Revision Request (PGRR) 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

RMGRR Number	176	RMGRR Title	Addition of Market Processes Specific to LP&L
Date of Decision		December 19, 2023	
Action		Recommended Approval	
Timeline		Urgent - to allow the market processes outlined in this Retail Market Guide Revision Request (RMGRR) to take effect in time for Lubbock Power & Light's (LP&L's) transition to retail competition which is planned to begin March 4, 2024.	
Proposed Effective Date		First of the month following Public Utility Commission of Texas (PUCT) approval	
Priority and Rank Assigned		Not applicable	
Retail Market Guide Sections Requiring Revision		8.4, Market Processes Specific to LP&L (new) 8.4.1, Safety-Nets (new) 8.4.1.1, Purpose (new) 8.4.1.2, Safety-Net Submission Processes (new) 8.4.1.3, Move-In/Reconnect Spreadsheet Format (new) 8.4.1.4, LP&L Safety-Net Response (new) 8.4.1.5, Transactional Reconciliation (new) 8.4.2, Standard Historical Usage Request (new) 8.4.2.1, Overview of the Letter of Authorization for Historical Usage (new) 8.4.3, Other Market Processes (new) 9 Appendix B1, Letter of Authorization for the Request of Historical Usage Information Form (English) 9 Appendix B2, Formulario Carta De Autorización Para Solicitar Información De Consumo Histórico (Letter of Authorization for the Request of Historical Usage Information Form – Spanish) 9 Appendix D4, Lubbock Power & Light (LP&L) Common Transactions and Timelines (new)	
Related Documents Requiring Revision/Related Revision Requests		None	
Revision Description		This RMGRR provides descriptions of the retail market processes that LP&L will utilize when they begin offering Customer Choice in their service territory.	

Board Report

Reason for Revision	☒ Addresses current operational issues. ☐ Meets Strategic goals (tied to the ERCOT Strategic Plan or directed by the ERCOT Board). ☐ Market efficiencies or enhancements ☐ Administrative ☐ Regulatory requirements ☐ Other: (explain) *(please select all that apply)*
Business Case	This RMGRR supports LP&L's decision to enter into retail competition and operate like an Investor Owned Utility (IOU) Transmission and/or Distribution Service Provider (TDSP) and outlines the retail market processes they will follow once they have entered into retail competition.
RMS Decision	On 11/7/23, RMS voted unanimously to grant RMGRR176 Urgent status; to recommend approval of RMGRR176 as submitted; and to forward to TAC RMGRR176. All Market Segments participated in the vote.
Summary of RMS Discussion	On 11/7/23, participants discussed the request for urgency and suggested that comments be filed if LP&L requires additional time before accepting rates. LP&L Staff confirmed acceptance of DocuSign in response to concerns regarding Retail Electric Providers (REPs) submitting ad hoc Letters of Authorization in anticipation of LP&L's entrance into the market.
TAC Decision	On 12/4/23, TAC voted unanimously to recommend approval of RMGRR176 as recommended by RMS in the 11/7/23 RMS Report; and the 11/14/23 Impact Analysis. All Market Segments participated in the vote.
Summary of TAC Discussion	On 12/4/23, TAC reviewed the 11/14/23 Impact Analysis, ERCOT Opinion, ERCOT Market Impact Statement, and Independent Market Monitor (IMM) Opinion for RMGRR176.
ERCOT Board Decision	On 12/19/23, the ERCOT Board voted unanimously to recommend approval of RMGRR176 as recommended by TAC in the 12/4/23 TAC Report.

Opinions

Board Report

Credit Review	Not Applicable
Independent Market Monitor Opinion	IMM has no opinion on RMGRR176.
ERCOT Opinion	ERCOT supports approval of RMGRR176.
ERCOT Market Impact Statement	ERCOT Staff has reviewed RMGRR176 and believes that it provides a positive market impact by addressing operational issues through descriptions of the retail market processes that LP&L will utilize when they begin offering Customer Choice in their service territory.

Sponsor	
Name	Michael Winegeart, on behalf of the Lubbock Retail Integration Task Force (LRITF)
E-mail Address	MWinegeart@mylubbock.us
Company	LP&L
Phone Number	806-775-3430
Cell Number	806-787-2044
Market Segment	Municipally Owned Utility (MOU)

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

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

None

Proposed Guide Language Revision

8.4 Market Processes Specific to LP&L

8.4.1 Safety-Nets

(1) This Section explains the steps that Market Participants must follow when processing safety-net move in Requests in Lubbock Power & Light's (LP&L's) service territory. This document is not intended to supersede or contradict P.U.C. SUBST. R. 25.487, Obligations Related to Move-In Transactions.

8.4.1.1 Purpose

(1) The Competitive Retailer (CR) establishes its responsibilities to serve a Customer at a Premise, which is identified by the Electric Service Identifier (ESI ID), beginning with the service start date that LP&L completes the move-in per the CR's move-in transaction or safety-net request, whichever date is earliest.

(2) The safety-net process is a manual work-around process used by Market Participants in the Texas retail market in the event that 814_16, Move-In Request, transactions are systematically delayed due to system degradation or complete system malfunction.

(3) The safety-net process may also be used during extended transaction processing outages, as described in Section 7.10, Emergency Operating Procedures for Extended Unplanned System Outages. However, under no circumstances should this safety-net process be used to bypass approved rules, Protocols, Guides and/or market-approved processes.

8.4.1.2 Safety-Net Submission Processes

(1) If LP&L provides an internet-based portal or a "Secure File Transfer Protocol" (SFTP) site for safety-net requests, the CR may submit a safety-net move in or reconnect spreadsheet requesting a move-in service start date or reconnection date of the current date by the following means:

(a) LP&L's specific internet-based or SFTP site submission process; and if the CR submits the safety-net spreadsheet via the SFTP site, then

(b) The CR must send an email to MarketOps@mylubbock.us notifying LP&L that they have submitted a safety-net spreadsheet in the SFTP site. The CR should not attach the safety-net spreadsheet to the email. The email "Subject Line" should be formatted as follows to match the safety-net spreadsheet file name:

[CR Name]_Safety Net_[Date<YYYYMMDD>_Time<HHMM>]_[Priority Type].xls

(2) If the CR utilizes the safety-net move in spreadsheet process, request(s) shall be submitted:

(a) Requesting a move-in service start date using the current Business Day;

(b) With standard and priority move-ins as separate spreadsheets;

(c) One time per day notification transmitted no later than 4:00 PM Central Prevailing Time (CPT); and

(d) Adhering to the format and content found in the following sections.

(3) Priority safety-net move in spreadsheets that are completed on the same-day or next day by LP&L may be charged priority move-in discretionary charges by LP&L according to LP&L's tariff, regardless of the priority code that is reflected in the corresponding 814_16, Move-In Request, transaction submitted by the CR for the same ESI ID and service start date.

8.4.1.3 Move-In/Reconnect Spreadsheet Format

(1) The CR will attach the spreadsheet with the safety-net acceptable data content in the format as indicated below in Table 23, Safety-Net Spreadsheet Content, to LP&L's internet-based portal or SFTP site.

(2) CRs must use the following naming convention for the safety-net spreadsheet file name: [CR Name]_Safety Net_[Date<YYYYMMDD>_Time<HHMM>]_[Priority Type].xls File names cannot be duplicated.

Examples: CR Name_Safety Net_20230123_1425_Standard MVI.xls
CR Name_Safety Net_20230417_1615_Priority MVI.xls
CR Name_Safety Net_20231105_0820_Emergency Reconnect.xls

Table 23. Safety-Net Spreadsheet Content

Column	Field Name	Note	Data Attributes	
			Type	Length (Min. / Max.)
(1)	ESI ID	(required)	AN	1 Min. / 80 Max.
(2)	Customer Name	(required)	AN	1 Min. / 60 Max.
(3)	Customer Phone	(required if available)	AN	1 Min. / 80 Max.
(4)	MVI Street Address	(required)	AN	1 Min. / 55 Max.
(5)	MVI Apartment Number	(if applicable)	AN	1 Min. / 55 Max.
(6)	MVI ZIP	(required)	ID	3 Min. / 15 Max.
(7)	MVI City	(required)	AN	2 Min. / 30 Max.
(8)	CR Data Universal Numbering System (DUNS) Number	(required)	AN	2 Min. / 80 Max.
(9)	CR Name	(prefer D/B/A to corporate name)	AN	1 Min. / 60 Max.

Column	Field Name	Note	Data Attributes	
			Type	Length (Min. / Max.)
(10)	MVI Request Date	(required)	DT	8 Min. / 8 Max.
(11)	Critical Care Flag	(optional)	AN	1 Min. / 30 Max.
(12)	BGN02	(required)	AN	1 Min. / 30 Max.
(13)	Notes/Directions	(optional)	AN	1 Min. / 80 Max.
(14)	CR Reason for Using Spreadsheet	(optional –free form)	AN	1 Min. / 80 Max.

(2) Row 1 of the spreadsheet is reserved for a title but is optional and at the discretion of the CR. The 'Field Name' header row shall begin on row 2 as shown below in the Example for Safety-Net Spreadsheet Format.

Example for Safety-Net Spreadsheet Format

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1														
2	ESI ID	Customer Name	Customer Phone	MVI Street Address	MVI Apartment Number	MVI ZIP	MVI City	CR DUNS Number	CR Name	MVI Request Date	Critical Care Flag	BGN02	Notes/Directions	CR Reason for Using Spreadsheet
3														
4														
5														
6														

8.4.1.4 LP&L Safety-Net Response

(1) Once the safety-net spreadsheet and email is received by LP&L, LP&L shall evaluate all of the ESI IDs included in the safety-net list to make a determination to schedule, complete unexecutable, or reject the Move-In Request. LP&L shall respond via email within one Business Day of receipt of the request.

(a) LP&L may reject or complete unexecutable the safety-net Move-In Request for the following applicable ESI ID(s) scenarios:

(i) If the "MVI Request Date" value(s) within the safety-net spreadsheet are other than the current date;

(ii) If construction service is required;

(iii) If an 814_16, Move-In Request, transaction has already been submitted by the CR for the specific ESI ID and has been accepted and scheduled by LP&L; or

(iv) If LP&L deems the ESI ID invalid or not in their service territory.

(b) LP&L shall notify the CR by attaching the spreadsheet in the market-approved spreadsheet format (see Table 24, TDSP Move-In Safety-Net Response Content) by email, MarkeTrak, or by means of an internet-based response if LP&L provides an internet-based portal, of all safety-net Move-In Requests that could not be completed as indicated below in Table 25, TDSP Return Codes.

Table 24. TDSP Move-In Safety-Net Response Content

Column	Field Name
(1)	ESI ID
(2)	MVI Street Address
(3)	MVI Apartment Number
(4)	MVI ZIP
(5)	MVI City
(6)	CR Name (D/B/A preferred)
(7)	MVI Request Date
(8)	BGN02 (optional)
(9)	TDSP Return Code
(10)	Complete Unexecutable or Reject Description (optional)

Table 25. TDSP Return Codes

Return Code	Description	Data Attributes	
		Type	Length Min./Max.
A76	ESI ID Invalid or Not Found	AN	1 Min. / 30 Max.
API	Required Information Missing	AN	1 Min. / 30 Max.
PT	Permit Required	ID	1 Min. / 2 Max.
09	Complete Unexecutable	AN	1 Min. / 2 Max.
SHF	Switch Hold Indicator	AN	1 Min. / 3 Max.

8.4.1.5 Transactional Reconciliation

(1) Per P.U.C. SUBST. R. 25.487, Obligations Related to Move-In Transactions, the CR shall ensure that the 814_16, Move-In Request, is submitted to ERCOT on or before the fifth Business Day after submitting the Move-In Request through the safety-net process.

(2) The CR shall submit an 814_16 to ERCOT and note the BGN02 on the safety-net spreadsheet that is sent to LP&L. All resubmitted 814_16 transactions must use the same requested date as submitted with the original safety-net spreadsheet. The CR may submit

a MarkeTrak issue after not receiving a response from ERCOT on their 814_16 transaction within 48 hours.

8.4.2 Standard Historical Usage Request

(1) With the Customer's authorization, CRs may request the Customer's historical data when they are not the Retail Electric Provider (REP) of record. This data includes the most recent 12 months of usage and is provided by the Transmission and/or Distribution Service Provider (TDSP) to the requesting CR. In order to provide the data to the CR, the TDSP must have written authorization (includes electronic authorization) from the Customer to allow the TDSP to provide the proprietary information. The TDSP will provide the requested data electronically in a Microsoft Excel© format within three Business Days of receipt of a valid Letter of Authorization for the Request of Historical Usage Information Form.

8.4.2.1 Overview of the Letter of Authorization for the Request of Historical Usage Information Form

(1) To obtain historical usage for an ESI ID, the requestor must submit the Letter of Authorization for the Request of Historical Usage Information Form to LP&L (see Section 9, Appendices, Appendix B1, Letter of Authorization for the Request of Historical Usage Information Form (English), and Appendix B2, Formulario Carta De Autorización Para Solicitar Información De Consumo Histórico (Letter of Authorization for the Request of Historical Usage Information Form – Spanish)). The Customer may allow the use of the same Letter of Authorization for the Request of Historical Usage Information Form by designating a specific expiration date on the form or designating the form as unlimited. The Customer must provide an expiration date or designate the form as unlimited.

(2) If the request is for a Premise with an Interval Data Recorder (IDR) Meter, the requesting CR shall indicate whether summary billing, interval data, or both summary billing and interval level data is required by checking the appropriate boxes. LP&L shall provide all data requested by the CR and authorized by the Customer, if available and shall use Section 9, Appendix B4, Transmission and/or Distribution Service Provider Response to Request for Historical Usage.

(3) When requesting historical usage from multiple TDSPs on the same Letter of Authorization for the Request of Historical Usage Information Form, the requestor must complete Section 9, Appendix B3, Requesting Historical Usage from Multiple Transmission and/or Distribution Service Providers, and attach it to the Letter of Authorization for the Request of Historical Usage Information Form. If forms are submitted via e-mail, the requestor shall place the Customer's name first when naming attachments, e.g., CustomerABC.xls, CustomerABC.pdf, CustomerABC-AEP.xls. LP&L will reject submitted ESI IDs that are not located within LP&L's territory.

8.4.3 Other Market Processes

LP&L will comply with the sections listed in Table 26, LP&L - Other Market Processes, below including each section's associated subsections unless specifically excluded, where they apply to a TDSP.

Table 26. LP&L - Other Market Processes

Market Process	Sections
Market Synchronization	7.2, Market Synchronization
Inadvertent Gain/Loss Process	7.3, Inadvertent Gain/Loss Process
Transaction Timing Matrix	7.7, Transaction Timing Matrix
Formal Invoice Dispute Process for Competitive Retailers and Transmission and/or Distribution Service Providers	7.8, Formal Invoice Dispute Process for Competitive Retailers and Transmission and/or Distribution Service Providers • For current LP&L tariff information, refer to P.U.C. SUBST. R. 25.219, Terms and Conditions of Access by a Competitive Retailer to the Delivery System of a Municipally Owned Utility or Electric Cooperative that Implements Customer Choice after May 1, 2023
No Retail Electric Provider of Record or Left in Hot	7.9, No Retail Electric Provider of Record or Left in Hot
Emergency Operating Procedures for Extended Unplanned System Outages	7.10, Emergency Operating Procedures for Extended Unplanned System Outages • LP&L will utilize the SFTP site where emails apply to Section 7.10 • LP&L will follow the safety-net process as

Market Process	Sections
	prescribed in Section 8.4.1, Safety-Nets
Transition Process	7.11, Transition Process
Estimated Meter Readings	7.12, Estimated Meter Readings • LP&L will utilize MarketOps@mylubbock.us for email correspondence referenced in Table 27, TDSP REP Relations E-mail Addresses, in Section 7.12.2, Estimations Due to Safety and/or Meter Removal
Out-flow Energy from Distributed Generation Facilities	7.14, Out-flow Energy from Distributed Generation Facilities
Advanced Meter Interval Data File Format and Submission	7.15, Advanced Meter Interval Data File Format and Submission • Excluding Section 7.15.3, Posting Data to Transmission and/or Distribution Service Provider File Transfer Protocol Site • Excluding paragraph (2) of Section 7.15.4, Availability of Interval Data for Provisioned Advanced Metering Systems
Transmission and/or Distribution Service Provider Switch Hold Notification for Meter Tampering	7.16.3, Transmission and/or Distribution Service Provider Switch Hold Notification for Meter Tampering

Market Process	Sections
Switch Hold Process for Meter Tampering	7.16.4, Switch Hold Process for Meter Tampering
Business Processes and Communications for Switch Holds Related to Deferred Payment Plans	7.17, Business Processes and Communications for Switch Holds Related to Deferred Payment Plans
Business Process for When a Customer Elects to Receive Non-Standard Metering Services	7.18, Business Process for When a Customer Elects to Receive Non-Standard Metering Services

[RMGRR176: Replace Section 8.4.3 above with the following upon system implementation of PR409-01, TX SET 5_0 and System Change Request (SCR) 817, Related to NPRR1095, MarkeTrak Validation Revisions Aligning with Texas SET V5.0:]

8.4.3 Other Market Processes

LP&L will comply with the sections listed in Table 26, LP&L - Other Market Processes, below including each section's associated subsections unless specifically excluded, where they apply to a TDSP.

Table 26. LP&L - Other Market Processes

Market Process	Sections
Market Synchronization	7.2, Market Synchronization
Inadvertent Gain/Loss Process	7.3, Inadvertent Gain/Loss Process
Transaction Timing Matrix	7.7, Transaction Timing Matrix
Formal Invoice Dispute Process for Competitive Retailers and Transmission and/or Distribution Service Providers	7.8, Formal Invoice Dispute Process for Competitive Retailers and Transmission and/or Distribution Service Providers • For current LP&L tariff information, refer to P.U.C. SUBST. R. 25.219, Terms and Conditions of Access by a Competitive Retailer to the Delivery

	System of a Municipally Owned Utility or Electric Cooperative that Implements Customer Choice after May 1, 2023
No Retail Electric Provider of Record or Left in Hot	7.9, No Retail Electric Provider of Record or Left in Hot
Emergency Operating Procedures for Extended Unplanned System Outages	7.10, Emergency Operating Procedures for Extended Unplanned System Outages • LP&L will utilize the SFTP site where emails apply to Section 7.10 • LP&L will follow the safety-net process as prescribed in Section 8.4.1, Safety-Nets
Transition Process	7.11, Transition Process
Estimated Meter Readings	7.12, Estimated Meter Readings • LP&L will utilize MarketOps@mylubbock.us for email correspondence referenced in Table 27, TDSP REP Relations E-mail Addresses, in Section 7.12.2, Estimations Due to Safety and/or Meter Removal
Out-flow Energy from Distributed Generation Facilities	7.14, Out-flow Energy from Distributed Generation Facilities
Advanced Meter Interval Data File Format and Submission	7.15, Advanced Meter Interval Data File Format and Submission • Excluding Section 7.15.3, Posting Data to Transmission and/or Distribution Service Provider File Transfer Protocol Site • Excluding paragraph (2) of Section 7.15.4, Availability

	of Interval Data for Provisioned Advanced Metering Systems
Transmission and/or Distribution Service Provider Switch Hold Notification for Meter Tampering	7.16.3, Transmission and/or Distribution Service Provider Switch Hold Notification for Meter Tampering
Switch Hold Process for Meter Tampering	7.16.4, Switch Hold Process for Meter Tampering
Business Processes and Communications for Switch Holds Related to Deferred Payment Plans	7.17, Business Processes and Communications for Switch Holds Related to Deferred Payment Plans
Business Process for When a Customer Elects to Receive Non-Standard Metering Services	7.18, Business Process for When a Customer Elects to Receive Non-Standard Metering Services
Business Processes Related to Continuous Service Agreements	7.19, Business Processes Related to Continuous Service Agreements

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Section 9: Appendices

Appendix B1: Letter of Authorization for the Request of Historical Usage Information Form (English)

~~February 1, 2019~~TBD

Appendix B1

Letter of Authorization for the Request of Historical Usage Information Form (English)

Reference: Section 7.5.1, Overview of the Letter of Authorization for Historical Usage

Date: _____ ☐ Unlimited ☐ Expiration Date_____

Select Transmission and/or Distribution Service Provider (TDSP) (Required: Select the TDSP the request applies to.)

☐Oncor	☐CenterPoint Energy	☐Nueces
☐AEP	☐TNMP	☐LP&L

Please accept this letter as a formal request and authorization for the above referenced TDSP to release energy usage data, including kWh, kVA or kW, and interval data (if applicable) at the following location(s) to <<(NAME OF Competitive Retailer (CR)/representative)>>. This information request shall be limited to no more than the most recent 12-month period of service. If the Electric Service Identifiers (ESI ID(s)) are metered using an Interval Data Recorder (IDR), please indicate whether summary level and/or interval data is required.

☐ Summary Billing Data Only ☐Interval Data Only ☐Both Summary and Interval Data

Please forward usage and Load information in electronic (Microsoft Excel) format using Retail Market Guide Section 9, Appendices, Appendix B4, Transmission and/or Distribution Service Provider Response to Request for Historical Usage, to:
E-mail: <<(EMAIL ADDRESS OF CR/REPRESENTATIVE)>>

If an attachment is used, please use a separate attachment per TDSP with the ESI IDs that are specific to a TDSP. The TDSP will reject submitted ESI IDs that are not located within the TDSP's territory.

Service Address	ESI ID Number (found on bill)

AUTHORIZATION

I affirm that I have the authority to make and sign this request on behalf of my company for all ESI IDs that are associated with this request.

_____ _____
(Signature) (Company)

☐ **By checking this box, (requesting party) _____ affirms that they have authorization from the Customer identified below to obtain Customer's historical usage information and holds the TDSP harmless for providing the historical data to requested party as identified on this form.**

_____ _____
(Name, printed) (Billing Street Address)

_____ _____
(Title) (City, State, Zip Code)

_____
(Telephone Number)

Board Report

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Appendix B2: Formulario Carta De Autorización Para Solicitar Información De Consumo Histórico (Letter of Authorization for the Request of Historical Usage Information Form – Spanish)

~~February 1, 2019~~TBD

Appendix B2

Formulario Carta De Autorización Para Solicitar Información De Consumo Histórico (Letter of Authorization for the Request of Historical Usage Information Form – Spanish)

Reference: Section 7.5.1, Overview of the Letter of Authorization for Historical Usage

Fecha: _____ ☐ Sin limite ☐ Fecha de vencimiento_____

Seleccione las empresas de transmisión y/o distribución (TDSP), (Requerido: Seleccione el TDSP a la que la petición se refiera)

☐Oncor	☐CenterPoint Energy	☐Nueces
☐AEP	☐TNMP	☐LP&L

Tenga la amabilidad de aceptar esta carta como una solicitud y autorización formal para que el TDSP mencionado anteriormente dé a conocer datos sobre su uso de energía, eléctrica lo que incluye kWh, kVA o kW, así como datos de intervalos (en caso de que corresponda) de los siguientes sitios a <<(NAME OF Competitive Retailer (CR)/representative)>>. La presente solicitud de información se limitará al último período de servicio de 12 meses. Si el/los Identificador(es) de Servicio Eléctrico (ESI ID (s)) son medidos usando un Registrador de Datos de Intervalo (IDR), por favor indican si los datos de intervalo y/o nivel sumarios son requeridos.

☐ Sólo Resumen de Factura ☐ Sólo información de intervalos ☐Información resumida y de intervalos

Por favor envíe la información de consumo y carga en formato electrónico (Microsoft Excel) usando la Guía de Mercado Minorista Sección 9, Apéndices, Apéndice B4, Transmisión y/o Distribución de Proveedor de Servicio Respuesta a la Petición de Uso Historial a: Correo electrónico: <<(EMAIL ADDRESS OF CR REPRESENTATIVE)>>

En caso de incluir un anexo, por favor utilice una hoja separada para cada TDSP con el ESI(s). El TDSP rechazará el/los ESI ID(s) sometidos que no esté(n) localizado(s) dentro del territorio del TDSP.

Domicilio del servicio Número del Identificador de Servicio Eléctrico(en la factura)

_____

_____

_____

AUTORIZACIÓN

Afirmo que tengo la autoridad para presentar y firmar esta solicitud en nombre de mi compañía, para todos los ESI IDs que estén relacionados con esta solicitud.

_____ _____
(Firma) (Compañía)

☐ **Al tildar esta casilla (la parte solicitante) _____ afirma que ellos tienen la autorización del Cliente identificado abajo para obtener la información de uso histórica del Cliente y sostener el TDSP inocuo para proporcionar los datos históricos al partido solicitado como identificado en esta forma.**

_____ _____
(Nombre, en letra de imprenta) (Domicilio de facturación)

_____ _____
(Cargo) (Ciudad, Estado, Código Postal)

_____
(Número de teléfono)

ERCOT Retail Market Guide

Section 9: Appendices

Appendix D4: Lubbock Power & Light (LP&L) Common Transactions and Timelines

TBD

Board Report

See electronic Microsoft Office Excel© file on the ERCOT Website posted with the Retail Market Guide

Appendix D4, Lubbock Power & Light (LP&L) Common Transactions and Timelines Effective upon implementation of Customer Choice in the LP&L service area							
Refer to Chapter 1: Definitions in paragraph P.U.C. SUBST. R 25.219(d), Tariff for Competitive Retailer Access, for the following terms: • Advanced Metering System (AMS) Operational Day • Business Day • Field Operational Day • First Available Switch Date (FASD)		Standard Meter AMS Remote (AMSR) (Remote Disconnect and Reconnect)			Non-Standard Meter Self-Contained, Current Transformer (CT) Meter, Interval Data Recorder (IDR), Mechanical, Non-Metered and AMS Manual (AMSM)		
Transaction Type	**Premise**	**If Received by:**	**Then Completed:**	**Otherwise Completed:**	**If Received by:**	**Then Completed:**	**Otherwise Completed:**
Move In	Existing Self-Contained	7:00 PM* on the requested date and the requested date is an AMS Operational Day	On the requested date	On the next AMS Operational Day	5:00 PM on a Business Day at least 2 Business Days prior to the requested date	On the requested date if it is a Business Day, on the next Business Day if the requested date is not a Business Day	With less than 2 Business Days notice, completed within 2 Business Days after the Business Day the order is considered received
	Existing CT/Other	N/A	N/A	N/A	Same as above	Same as above	Same as above
	New Self-Contained	5:00 PM on a Business Day at least 2 Business Days prior to	On the requested date if it is a Business Day	Within 2 Business Days after the Business Day the	Same as above	Same as above	Same as above

			the requested date		order is considered received			
		New CT/Other Meter	N/A	N/A	N/A	Same as above	Same as above	Same as above
Priority Move In		Existing Self-Contained	N/A	N/A	N/A	5:00 PM on the requested date	On the requested date if it is a Business Day	The Business Day following the requested date
		Existing CT/Other	N/A	N/A	N/A	Same as above	Same as above	Same as above
		New Self-Contained	N/A	N/A	N/A	N/A	N/A	N/A
		New CT/Other Meter*	N/A	N/A	N/A	N/A	N/A	N/A
Move-Out		All	7:00 PM on the requested date and the requested date is an AMS Operational Day	On the requested date	On the next AMS Operational Day	5:00 PM on a Business Day at least 2 Business Days prior to the requested date	On the requested date if it is a Business Day, on the next Business Day if the requested date is not a Business Day	With less than 2 Business Days notice, completed within 2 Business Days after the Business Day the order is considered received
Disconnect for Non-Pay***		At meter Same-day	3:00 PM on the requested date	Within 2 hours of receipt if requested date is a	By 9:00 AM on the next Business Day	N/A	N/A	N/A

					Business Day				
		At meter Future date		11:59:59 PM on a day preceding the requested date	By 9:00 AM on the requested date if it is a Business Day	By 9:00 AM on the next Business Day	5:00 PM at least 2 Business Days prior to the requested date	Within 3 Business Days of requested date (if requested date is not a Business Day, the next Business Day shall be treated as the requested date).	With less than 2 Business Days notice, completed within 4 Business Days after the Business Day the order is considered received, but not before the requested date
		At Premium Location		5:00 PM at least 2 Business Days prior to the requested date	Within 3 Business Days of the requested date	Within 4 Business Days after the order is received	Same as above	Same as above	Same as above
Reconnect after Disconnect for Non-Pay Must complete all Reconnects within 48 hours of Receipt		At meter		24/7/365	Within 2 hours of receipt of the request		3:00 PM on a Business Day	On the Business Day received	On the Business Day received if possible, otherwise completed by the close of the next Field Operational Day

						7:00 PM on a Business Day	On the Business Day received	On the next Field Operational Day
						If compliance with the 48 hour reconnection requirement results in reconnection being performed on a weekend.		
						If compliance with the 48 hour reconnection requirement results in reconnection being performed on a holiday.		
		At Premium Location	3:00 PM on the Business Day	On the day received	On the day received if possible, otherwise completed by the close of the next Field Operational Day	3:00 PM on a Business Day	On the Business Day received	On the Business Day received if possible, otherwise completed by the close of the next Field Operational Day
			7:00 PM on a Business Day	On the Business Day received	By the close of the next Field Operational Day	7:00 PM on a Business Day	On the Business Day received	On the next Field Operational Day
			If compliance with the 48 hour reconnection requirement results in reconnection being performed on a weekend.			If compliance with the 48 hour reconnection requirement results in reconnection being performed on a weekend.		
			If compliance with the 48 hour reconnection requirement results in reconnection being performed on a holiday.			If compliance with the 48 hour reconnection requirement results in reconnection being performed on a holiday.		

Board Report

Standard Switch	All		By 7:00 PM on an AMS Operational Day	On the day received (FASD**)	On the next AMS Operational Day	AMS-M has the same timeline as Standard Meter; All others, not applicable	AMS-M has the same timeline as Standard Meter; All others, completed within 4 Business Days of the FASD**	AMS-M has the same timeline as Standard Meter; All others, not applicable
Self-selected Switch	All		By 7:00 PM on the requested AMS Operational Day	On the requested date	On the next AMS Operational Day	AMS-M has the same timeline as Standard Meter; All others, 5:00 PM at least 2 Business Days prior to the requested date	AMS-M has the same timeline as Standard Meter; All others, on the requested date if it is a Business Day	Within 2 Business Days after the Business Day the order is considered received

Revised: TBD

* All times listed in this table are Central Prevailing Time (CPT).
** The FASD is Day 0 unless otherwise specified by the registration agent.
*** No disconnections: 1) Between 5:00 PM and 7:00 AM unless coordinated disconnect between CR and Transmission and/or Distribution Service Provider (TDSP); 2) Prior to a holiday or during a weather moratorium as per Lubbock Power & Light Customer Protection Rules relating to P.U.C. SUBST. R. 25.483, Disconnection of Service.

NOTES:

1. This chart attempts to condense the provisions/requirements found in P.U.C. SUBST. R. 25.219, Terms and Conditions of Access by a Competitive Retailer to the Delivery System of a Municipally Owned Utility or Electric Cooperative that Implements Customer Choice after May 1, 2023. This chart may not cover all situations and circumstances. To the extent there is a conflict between this chart and either Rule 25.219 or LP&L's tariff, the Rule or tariff will control, respectively.

2. The timelines in the chart only apply if required inspections, permits, or other construction has been completed.

ERCOT Impact Analysis Report

RMGRR Number	176	RMGRR Title	Addition of Market Processes Specific to LP&L
Impact Analysis Date		November 14, 2023	
Estimated Cost/Budgetary Impact		None.	
Estimated Time Requirements		No project required. This Retail Market Guide Revision Request (RMGRR) 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.