(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, 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, 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, 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, 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,	From LSL to 0 MW	-$250.00

the lowest MW point on the Energy Bid/Offer Curve is greater than zero	From 0 MW to lowest MW point on submitted Energy Bid/Offer Curve	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 Curve that does not cover the full range of the Resource's available Demand response capability, consistent with the ~~Controllable Load Resource~~CLR'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 Curve	Price associated with the lowest MW in submitted ~~RTM~~ Energy Bid ~~e~~Curve
MPC minus maximum MW of ~~RTM~~ Energy Bid Curve to MPC	~~RTM~~ Energy Bid ~~e~~Curve
MPC	Right-most point (lowest price) on ~~RTM~~ Energy Bid ~~e~~Curve

(9) For a CLR whose QSE has not submitted an Energy Bid Curve, consistent with the CLR's telemetered quantities, ERCOT shall create a proxy Energy Bid Curve as described below:

MW	Price (per MWh)
LPC to MPC	SWCAP

(10) ERCOT shall ensure that any RTM Energy Bid Curve is monotonically non-increasing. The QSE representing the Controllable Load ResourceCLR shall be responsible for all RTM Energy Bid Curves, including bidsEnergy Bid Curves updated by ERCOT as described above.

(11) A CLR may consume energy only when dispatched by SCED to do so. A CLR may telemeter a status of OUTL only if the Resource is Off-Line and unavailable with its energy consumption at zero. 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 In instances when the Controllable Load ResourceCLR is unable to follow SCED Dispatch Instructions but still consumes energy, the CLR must submit a Resource Status of ONHOLD. Under all telemetered statuses, including OUTL, the remaining telemetry quantities submitted by the QSE shall represent the operating conditions of the Controllable Load ResourceCLR that can be verified by ERCOT. A QSE representing a Controllable Load ResourceCLR with a telemetered status of OUTL or ONHOLD is still obligated to provide any applicable Ancillary Services awarded to the Resource. This paragraph does not apply to ESRs.

(12) 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.

(13) 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.

(14) 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.

(15) 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 Bid Curves from available Controllable Load

~~Resources~~CLRs, 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 ~~e~~Curves for all available ~~Controllable Load Resources~~CLRs, whether submitted by QSEs or created by ERCOT. There is no mitigation of ~~RTM~~ Energy Bid Curves. An ~~RTM~~ Energy Bid Curve from an Aggregate~~Controllable~~ Load Resource (ALR) represents the bid for energy distributed across all nodes in the Load Zone in which the ALR~~Controllable Load Resource~~ is located. For an ESR or a CLR that is not an ALR, an ~~RTM~~ Energy Bid Curve represents a bid for energy at the applicable~~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.

(16~~5~~) 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.

(17~~6~~) ERCOT may override one or more of a ~~Controllable Load Resource~~CLR's parameters in SCED if ERCOT determines that the ~~Controllable Load Resource~~CLR's participation is having an adverse impact on the reliability of the ERCOT System.

(18~~7~~) 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.

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

Commented [CP9]: Please note NPRRs 1214, 1235, 1238, and 1245 also propose revisions to this section.

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

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

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

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

(d) Deployed ERS;

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

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

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

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

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

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

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

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

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

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

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

(d) For all ~~Controllable Load Resources~~CLRs excluding ones with a telemetered status of OUTL, ONTEST, or ONHOLD:

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

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

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

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

The above parameter is defined as follows:

Parameter	Unit	Current Value*
RHours	Hours	4.5

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

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

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

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

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

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

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

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

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

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

(p) The Real-Time On-Line Reliability Deployment Price Adder is the minimum of items (n) and (o) above except when ERCOT is directing firm Load shed during EEA Level 3. When ERCOT is directing firm Load shed during EEA Level 3 to either maintain sufficient PRC or stabilize grid frequency, as described in paragraph (3) of Section 6.5.9.4.2, the Real-Time On-Line Reliability Deployment Price Adder is the VOLL minus the sum of the System Lambda of the second step in the two-step SCED process described in paragraph (10)(b) of

Section 6.5.7.3 and the Real-Time On-Line Reserve Price Adder. Once ERCOT is no longer directing firm Load shed, as described above, the Real-Time On-Line Reliability Deployment Price Adder will again be set as the minimum of items (n) and (o) above.

[NPRR904, NPRR1006, NPRR1010, NPRR1014, NPRR1091, and NPRR1105: Replace applicable portions of Section 6.5.7.3.1 above with the following upon system implementation for NPRR904, NPRR1006, NPRR1014, NPRR1091, or NPRR1105; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.5.7.3.1 Determination of Real-Time Reliability Deployment Price Adder

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

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

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

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

(d) Deployed ERS;

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

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

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

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

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

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

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

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

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

(n) ERCOT-directed deployment of Off-Line Non-Spin.

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

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

(i) Set the LSL and LDL to zero;

(ii) Remove all Ancillary Service Offers; and

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

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

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

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

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

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

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

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

(d) For all On-Line ESRs:

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

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

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

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

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

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

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

The above parameter is defined as follows:

Parameter	Unit	Current Value*
RHours	Hours	4.5

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

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

(i) Add the MW from DC Tie export curtailments during an EEA or transmission emergency, to address local transmission system limitations, or due to an emergency action by a neighboring system operator during an emergency that is accommodated by ERCOT to GTBD. The amount of MW is determined from

the Dispatch Instruction and should continue over the duration of time specified by the ERCOT Operator. The MW added to GTBD associated with any individual DC Tie shall not exceed the higher of DC Tie advisory limit for exports on that tie as of 0600 in the Day-Ahead or subsequent advisory export limit minus the aggregate export on the DC Tie that remained scheduled following the Dispatch Instruction from the ERCOT Operator.

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

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

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

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

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

subsequent changes to this value, will be communicated to Market Participants in a Market Notice. After recall, an approximation of the amount of un-restored TDSP standard offer Load management programs shall be used. GTBD shall be adjusted to reflect restoration on a linear curve over the assumed restoration period ("RHours") defined by item (g) above.

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

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

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

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

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

6.5.7.4 Base Points

Commented [CP10]: Please note NPRR1246 also proposes revisions to this section.

(1) ERCOT shall issue a Base Point for each On-Line Generation Resource and each On-Line Controllable Load Resource (CLR) on completion of each SCED execution. The Base Point set by SCED must observe a Generation Resource's and ~~Controllable Load Resource~~CLR's HDL and LDL. Base Points are automatically superseded on receipt of a new Base Point from ERCOT regardless of the status of any current ramping activity of a Resource. ERCOT shall provide each Base Point using Dispatch Instructions issued over Inter-Control Center Communications Protocol (ICCP) data link to the QSE representing each Resource that include the following information:

(a) Resource identifier that is the subject of the Dispatch Instruction;

(b) MW output for Generation Resource and MW consumption for ~~Controllable Load Resource~~CLR;

(c) Time of the Dispatch Instruction;

(d) Flag indicating SCED has dispatched a Generation Resource or ~~Controllable Load Resource~~CLR below HDL used by SCED or an IRR has been instructed not to exceed its Base Point;

[NPRR285: Insert paragraph (e) below upon system implementation and renumber accordingly:]

(e) Flag indicating SCED has dispatched a Generation Resource away from the Output Schedule submitted for that Generation Resource;

(e) Flag indicating that the Resource is identified for mitigation pursuant to paragraph (7) of Section 3.19.4, Security-Constrained Economic Dispatch Constraint Competitiveness Test, and paragraph (10) of Section 6.5.7.3, Security Constrained Economic Dispatch; and

(f) Other information relevant to that Dispatch Instruction.

(2) Each Generation Resource and CLR shall follow ERCOT-issued Updated Desired Base Points plus any Regulation Service deployments, unless otherwise instructed by ERCOT. ERCOT-issued Updated Desired Base Points shall not include deployed Regulation Service or expected Primary Frequency Response.

6.5.7.5 Ancillary Services Capacity Monitor

Commented [CP11]: Please note NPRRs 1235 and 1244 also propose revisions to this section.

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

(a) RRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

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

(b) Ancillary Service Resource Responsibility for RRS from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

(iv) Resources capable of FFR;

(c) ECRS capacity from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources; and

(iv) Quick Start Generation Resources (QSGRs);

(d) Ancillary Service Resource Responsibility for ECRS from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources; and

(iii) Controllable Load Resources; and

(iv) QSGRs;

(e) ECRS deployed to Generation and Load Resources;

(f) Non-Spin available from:

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

(ii) Undeployed Load Resources;

(iii) Off-Line Generation Resources; and

(iv) Resources with Output Schedules;

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

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

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

(iii) Load Resources;

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

(v) QSGRs;

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

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

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

(k) Available capacity:

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

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

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

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

(v) With ~~RTM~~ Energy Bid ~~e~~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 ~~e~~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:

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

$PRC_1 =$ **Min(Max((RDF*(HSL-NFRC) – 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.

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

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

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

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

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

PRC_5 = 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 and carrying Ancillary Service Resource Responsibility

$PRC_6 = \sum_{i=online\ load\ resource}^{All\ online\ load\ resources}$ 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 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, NPRR1029, and NPRR1204: Replace applicable portions of Section 6.5.7.5 above with the following upon system implementation for NPRR1014 or NPRR1029; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010 and NPRR1204:]

6.5.7.5 Ancillary Services Capacity Monitor

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

(a) RRS capability from:

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

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

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

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

(v) ESRs, in the form of FFR, that can be sustained for the SCED duration requirements of FFR;

(b) Ancillary Service Resource awards for RRS to:

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

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

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

(iv) Resources providing FFR;

(c) ECRS capability from:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources;

(iii) Controllable Load Resources;

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

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

(d) Ancillary Service Resource awards for ECRS to:

(i) Generation Resources;

(ii) Load Resources excluding Controllable Load Resources; and

(iii) Controllable Load Resources;

(iv) QSGRs; and

(v) ESRs.

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

(f) Non-Spin available from:

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

(ii) Undeployed Load Resources;

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

(iv) Resources with Output Schedules; and

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

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

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

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

(iii) Load Resources;

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

(v) QSGRs; and

(vi) ESRs.

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

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

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

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

(l) Available capacity:

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

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

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

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

(v) With ~~RTM~~ Energy Bid ~~c~~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 ~~c~~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.

$PRC_3 =$	$\sum_{i=\text{online generation resource}}^{\text{All online generation resources}}$	((Synchronous condenser output)$_i$ as qualified by item (8) of Operating Guide Section 2.3.1.2, Additional Operational Details for Responsive Reserve and ERCOT Contingency Reserve Service Providers))
$PRC_4 =$	$\sum_{i=\text{online load resource}}^{\text{All online load resources}}$	(Min(Max((Actual Net Telemetered Consumption – LPC), 0.0), ECRS and RRS Ancillary Service Resource award * 1.5) from all Load Resources controlled by high-set under-frequency relays with an ECRS and/or RRS Ancillary Service Resource award)$_i$
$PRC_5 =$	$\sum_{i=\text{online load resource}}^{\text{All online load resources}}$	Min(Max((LRDF_1*Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_1 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED with an Ancillary Service Resource award
$PRC_6 =$	$\sum_{i=\text{online load resource}}^{\text{All online load resources}}$	Min(Max((LRDF_2 * Actual Net Telemetered Consumption – LPC)$_i$, 0.0), (0.2 * LRDF_2 * Actual Net Telemetered Consumption)) from all Controllable Load Resources active in SCED without an Ancillary Service Resource award
$PRC_7 =$	$\sum_{i=\text{online FFR resource}}^{\text{All online FFR resources}}$	(Capacity from Resources capable of providing FFR)$_i$

$PRC_8 = \sum_{i=online\ ESR}^{All\ online\ ESR}$ **(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.

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

Excludes DC-Coupled Resource capacity used to provide FFR.

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

The above variables are defined as follows:

Variable	Unit	Description
PRC_1	MW	Generation On-Line greater than 0 MW
PRC_2	MW	WGRs On-Line greater than 0 MW
PRC_3	MW	Synchronous condenser output
PRC_4	MW	Capacity from Load Resources with an ECRS Ancillary Service Resource award
PRC_5	MW	Capacity from Controllable Load Resources active in SCED 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_1		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources awarded an Ancillary Service Resource award
LRDF_2		The currently approved Load Resource Reserve Discount Factor for Controllable Load Resources not awarded an Ancillary Service Resource award
FRCHL	MW	Telemetered High limit of the FRC for the Resource
FRCO	MW	Telemetered output of FRC portion of the Resource

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

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

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

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

(1) ERCOT shall deploy Non-Spin Service by operator Dispatch Instruction for the portion of On-Line Generation Resources that is only available through power augmentation and participating as Off-Line Non-Spin, Off-Line Generation Resources, and Load Resources that are not Controllable Load Resources. ERCOT shall develop a procedure approved by TAC to deploy Resources providing Non-Spin Service. ERCOT Operators shall implement the deployment procedure when a specified threshold(s) in MW of capability available to SCED to increase generation is reached. ERCOT Operators may implement the deployment procedure to recover deployed RRS, ECRS, or when other Emergency Conditions exist. The deployment of Non-Spin must always be 100% of that scheduled on an individual Resource.

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

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

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

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

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

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

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

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

Schedule to account for such deployment and to make the energy from the full amount of the Non-Spin Ancillary Service Resource Responsibility available to SCED. A Non-Spin deployment Dispatch Instruction from ERCOT is not required and these Resources must be able to Dispatch their Non-Spin Ancillary Service Resource Responsibility in response to a SCED Base Point deployment instruction. The provisions of this paragraph (5) do not apply to:

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

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

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

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

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

(10) Each QSE providing Non-Spin from a Resource shall inform ERCOT of the Non-Spin Resource availability using the Resource Status and Non-Spin Ancillary Service

Resource Responsibility indications for the Operating Hour using telemetry and shall use the COP to inform ERCOT of Non-Spin Resource Status and Non-Spin Ancillary Service Resource Responsibility for hours in the Adjustment Period through the end of the Operating Day.

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

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

(a) The Resource name;

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

(c) The anticipated duration of deployment.

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

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

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

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

6.5.7.6.2.3 Non-Spinning Reserve Service Deployment

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

exist. The deployment of Non-Spin must always be 100% of that awarded on an individual Resource.

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

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

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

(a) Controllable Load Resources awarded Non-Spin shall have an ~~RTM~~ Energy ~~Bid~~Curve for SCED and shall be capable of being Dispatched to its Non-Spin Ancillary Service award within 30 minutes, using the Resource's Normal Ramp Rate curve. An Aggregate Load Resource (ALR) must comply with all requirements in Section 22, Attachment O, Requirements for Aggregate Load Resource Participation in the ERCOT Markets.

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

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

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

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

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

(b) Any Generation Resource providing Off-Line Non-Spin that did not previously receive group assignment will be automatically considered in Group 1. Any Load Resource that is not a Controllable Load Resource providing Non-Spin in

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

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

(a) The Resource name;

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

(c) The anticipated duration of deployment.

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

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

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

6.6.1.2 Real-Time Settlement Point Price for a Load Zone

(1) The Real-Time Settlement Point Price for a Load Zone Settlement Point is based on the state-estimated Load in MW and the time-weighted average Real-Time LMPs at Electrical Buses that are included in the Load Zone. The Real-Time Settlement Point Price for a Load Zone Settlement Point for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP} = \mathbf{Max}\left(-\$251, \left(\left(\sum_{y} \mathbf{TLMP}_{y} * \mathbf{LZLMP}_{y}\right) / \sum_{y} \mathbf{TLMP}_{y}\right) + \mathbf{RTRSVPOR} + \mathbf{RTRDP}\right)$$

For all Load Zones except Direct Current Tie (DC Tie) Load Zones:

$$LZLMP_{y} = \sum_{b} \left(RTLMP_{b,y} * SEL_{b,y}\right) / \sum_{b} SEL_{b,y}$$

For a DC Tie Load Zone:

$$LZLMP_y = RTLMP_{b,y}$$

Where:

$$RTRSVPOR = \sum_y (RNWF_y * RTORPA_y)$$

$$RTRDP = \sum_y (RNWF_y * RTORDPA_y)$$

$$RNWF_y = TLMP_y / \sum_y TLMP_y$$

[NPRR1010: Replace paragraph (1) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(1) The Real-Time Settlement Point Price for a Load Zone Settlement Point is based on the state-estimated Load in MW and the time-weighted average Real-Time LMPs at Electrical Buses that are included in the Load Zone. The Real-Time Settlement Point Price for a Load Zone Settlement Point for a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTSPP = Max\ (-\$251,\ ((\sum_y TLMP_y * LZLMP_y) / \sum_y TLMP_y) + RTRDP)}$$

For all Load Zones except Direct Current Tie (DC Tie) Load Zones:

$$LZLMP_y = \sum_b (RTLMP_{b,y} * SEL_{b,y}) / \sum_b SEL_{b,y}$$

For a DC Tie Load Zone:

$$LZLMP_y = RTLMP_{b,y}$$

Where:

$$RTRDP = \sum_y (RNWF_y * RTRDPA_y)$$

$$RNWF_y = TLMP_y / \sum_y TLMP_y$$

(2) For all Settlement calculations in which a 15-minute Real-Time Settlement Point Price for a Load Zone is required in order to perform Settlement for a 15-minute quantity that is represented as one value (the integrated value for the 15-minute interval) but varies

with each SCED interval within the 15-minute Settlement Interval, an energy-weighted Real-Time Settlement Point Price shall be used and is calculated as follows:

$$\mathbf{RTSPPEW} = \mathbf{Max}\left[-\$251, \left(\sum_{y}\sum_{b}(\mathbf{RTLMP}_{b,y} * \mathbf{LZWF}_{b,y}) + \mathbf{RTRSVPOR} + \mathbf{RTRDP}\right)\right]$$

For all Load Zones except DC Tie Load Zones:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_{y}) / \left[\sum_{y}\sum_{b}(SEL_{b,y} * TLMP_{y})\right]$$

For a DC Tie Load Zone:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_{y}) / \left[\sum_{y}\sum_{b}(SEL_{b,y} * TLMP_{y})\right]$$

$$SEL_{b,y} = 1$$

Where:

$$RTRSVPOR = \sum_{y}(RNWF_{y} * RTORPA_{y})$$

$$RTRDP = \sum_{y}(RNWF_{y} * RTORDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point, for the 15-minute Settlement Interval.
RTSPPEW	$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the state-estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Interval.
$RTLMP_{b,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
$RTORPA_{y}$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time Price Adder for On-Line Reserves for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.

$RTORDPA_y$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder*—The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$LZWF_{b,y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone Settlement Point Price calculation for Electrical Bus *b*, for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$LZLMP_y$	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED interval *y*.
$SEL_{b,y}$	MW	*State Estimator Load at bus per interval*—The Load value from State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for Distribution Generation Resource (DGR) and Distribution Energy Storage Resource (DESR) injections and withdrawals that are settled at a Resource Node, excluding Controllable Load Resource (CLR) Load that is not an ALR, Wholesale Storage Load (WSL) and Non-WSL Energy Storage Resource (ESR) Charging Load for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$TLMP_y$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

[NPRR1010: Replace paragraph (2) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

(2) For all Settlement calculations in which a 15-minute Real-Time Settlement Point Price for a Load Zone is required in order to perform Settlement for a 15-minute quantity that is represented as one value (the integrated value for the 15-minute interval) but varies with each SCED interval within the 15-minute Settlement Interval, an energy-weighted Real-Time Settlement Point Price shall be used and is calculated as follows:

$$\mathbf{RTSPPEW} = \mathbf{Max}\left[-\$251, \left(\sum_{y}\sum_{b}(\mathbf{RTLMP}_{b,y} * \mathbf{LZWF}_{b,y}) + \mathbf{RTRDP}\right)\right]$$

For all Load Zones except DC Tie Load Zones:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_y) / \left[\sum_{y}\sum_{b}(SEL_{b,y} * TLMP_y)\right]$$

For a DC Tie Load Zone:

$$LZWF_{b,y} = (SEL_{b,y} * TLMP_y) / \left[\sum_{y}\sum_{b}(SEL_{b,y} * TLMP_y)\right]$$

$$SEL_{b,y} = 1$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The above variables are defined as follows:

Variable	Unit	Description
RTSPP	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point, for the 15-minute Settlement Interval.
RTSPPEW	$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the state-estimated Load of the Load Zone of each SCED interval within the 15-minute Settlement Interval.
$RTLMP_{b,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$LZWF_{b,y}$	none	*Load Zone Weighting Factor per bus per interval*—The weight used in the Load Zone Settlement Point Price calculation for Electrical Bus *b*, for the portion of the SCED interval *y* within the 15-minute Settlement Interval.
$LZLMP_{y}$	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED interval *y*.
$SEL_{b,y}$	MW	*State Estimator Load at bus per interval*—The Load value from State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for Distribution Generation Resource (DGR) and Distribution Energy Storage Resource (DESR) injections and withdrawals that are settled at a Resource Node, excluding Controllable Load Resource (CLR) Load that is not an ALR, Wholesale Storage Load (WSL) and Non-WSL Energy Storage Resource (ESR) Charging Load, for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the portion of the SCED interval *y* within the Settlement Interval.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

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6.6.1.4 Load Zone LMPs

(1) The Load Zone LMPs shall be posted on the ERCOT website. The Load Zone LMP is based on the state-estimated Loads in MW and the Real-Time LMPs at the Electrical Buses included in the Load Zone. The Load Zone LMP for a Load Zone for a SCED interval is calculated as follows:

$$\mathbf{LZLMP}_{y} = \sum_{b} (\mathbf{RTLMP}_{b,y} * \mathbf{LZWF}_{b,y})$$

For all Load Zones except DC Tie Load Zones:

$$\mathbf{LZWF}_{b,y} = \mathbf{SEL}_{b,y} / (\sum_{b} \mathbf{SEL}_{b,y})$$

For a DC Tie Load Zone:

$$\mathbf{LZWF}_{b,y} = [\mathbf{Max}\ (0.001, \mathbf{SEL}_{b,y})] \ / \ [\mathbf{Max}\ (0.001, \mathbf{SEL}_{b,y})]$$

The above variables are defined as follows:

Variable	Unit	Description
$LZLMP_y$	$/MWh	*Load Zone Locational Marginal Price*—The Load Zone LMP for the Load Zone for the SCED interval *y*.
$RTLMP_{b,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per SCED interval*—The Real-Time LMP at Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
$LZWF_{b,y}$	None	*Load Zone State Estimator Load Weighting Factor per bus per SCED interval*—The weight used in the Load Zone LMP calculation for Electrical Bus *b* for the SCED interval *y*.
$SEL_{b,y}$	MW	*State Estimator Load at bus per SCED interval*—The Load from the State Estimator, including a calculated net Load value at each Private Use Network and adjustments to account for DGR and DESR injections and withdrawals that are settled at a Resource Node, excluding CLR Load that is not an ALR, WSL and Non-WSL ESR Charging Load for Electrical Bus *b* in the Load Zone, for the SCED interval *y*.
y	None	A SCED interval.
b	None	An Electrical Bus in the Load Zone. The summation is over all of the Electrical Buses in the Load Zone.

6.6.3.1 Real-Time Energy Imbalance Payment or Charge at a Resource Node

(1) The payment or charge to each QSE for Energy Imbalance Service is calculated based on the Real-Time Settlement Point Price for the following amounts at a particular Resource Node Settlement Point:

(a) The energy produced or consumed at the Settlement Point by all its Generation Resources, ESR Charging Load with WSL treatment, ESR Charging Load with Non-WSL treatment, or CLRs that are not Aggregate Load Resources (ALRs)~~consumed as WSL, or consumed as Non-WSL ESR Charging Load at the Settlement Point~~; plus

(b) The amount of its Self-Schedules with sink specified at the Settlement Point; plus

(c) The amount of its Day-Ahead Market (DAM) Energy Bids cleared in the DAM at the Settlement Point; plus

(d) The amount of its Energy Trades at the Settlement Point where the QSE is the buyer; minus

(e) The amount of its Self-Schedules with source specified at the Settlement Point; minus

(f) The amount of its energy offers cleared in the DAM at the Settlement Point; minus

(g) The amount of its Energy Trades at the Settlement Point where the QSE is the seller.

(2) The payment or charge to each QSE for Energy Imbalance Service at a Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMT}_{q,p} = \mathbf{(-1)} * \{ \sum_{gsc} (\sum_{r} \mathbf{(RESREV}_{q,r,gsc,p})) + (\sum_{r} \mathbf{WSLAMTTOT}_{q,r,p}) + (\sum_{r} \underline{\mathbf{CLRAMTTOT}_{q,r,p}}) + (\sum_{r} \mathbf{ESRNWSLAMTTOT}_{q,r,p}) + \mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * ¼) + (\mathbf{DAEP}_{q,p} * ¼) + (\mathbf{RTQQEP}_{q,p} * ¼) - (\mathbf{SSSR}_{q,p} * ¼) - (\mathbf{DAES}_{q,p} * ¼) - (\mathbf{RTQQES}_{q,p} * ¼)]\}$$

Where:

$\mathrm{RESREV}_{q,r,gsc,p}$ = $\mathrm{GSPLITPER}_{q,r,gsc,p} * \mathrm{NMSAMTTOT}_{gsc}$

$\mathrm{RESMEB}_{q,r,gsc,p}$ = $\mathrm{GSPLITPER}_{q,r,gsc,p} * \mathrm{NMRTETOT}_{gsc}$

$\mathrm{WSLTOT}_{q,p}$ = $\sum_{r} (\sum_{b} \mathrm{MEBL}_{q,r,b})$

$\underline{\mathrm{CLRTOT}_{q,p}}$ = $\underline{\sum_{r} (\sum_{b} \mathrm{MEBCL}_{q,r,b})}$

$\mathrm{ESRNWSLTOT}_{q,p}$ = $\sum_{r} (\sum_{b} \mathrm{MEBR}_{q,r,b})$

$\mathrm{RNIMBAL}_{q,p}$ = $\sum_{gsc} (\sum_{r} \mathrm{RESMEB}_{q,r,gsc,p}) + \mathrm{WSLTOT}_{q,p} + \underline{\mathrm{CLRTOT}_{q,p}} + \mathrm{ESRNWSLTOT}_{q,p} + (\mathrm{SSSK}_{q,p} * ¼) + (\mathrm{DAEP}_{q,p} * ¼) + (\mathrm{RTQQEP}_{q,p} * ¼) - (\mathrm{SSSR}_{q,p} * ¼) - (\mathrm{DAES}_{q,p} * ¼) - (\mathrm{RTQQES}_{q,p} * ¼)$

The above variables are defined as follows:

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Variable	Unit	Description
RTEIAMT $_{q, p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RNIMBAL $_{q, p}$	MWh	*Resource Node Energy Imbalance per QSE per Settlement Point*—The Resource Node volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSK $_{q, p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids and Energy Bid Curves at Settlement Point *p*, cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q, p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RESREV $_{q, r, gsc, p}$	$	*Resource Share Revenue Settlement Payment*—The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
RESMEB $_{q, r, gsc, p}$	MWh	*Resource Share Net Meter Real-Time Energy Total*—The Resource share of the net sum for all Settlement Meters attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
WSLTOT $_{q, p}$	MWh	*WSL Total*—The total WSL energy metered by the Settlement Meters which measure WSL for the QSE *q* at Settlement Point *p*.
CLRTOT $_{q, p}$	MWh	*CLR Load Total*—The total energy metered by the Settlement Meters which measures CLR Load for the QSE *q* at Settlement Point *p*.
ESRNWSLTOT $_{q, p}$	MWh	*ESR Non-WSL Total*—The total energy metered by the Settlement Meters which measures Non-WSL ESR Charging Load for the QSE *q* at Settlement Point *p*.
MEBL $_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.

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Variable	Unit	Description
MEBCL$_{q, r, b}$	MWh	*Calculated Metered Energy for CLR Load at Bus*—The calculated CLR Load, adjusted for Unaccounted For Energy (UFE), for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBR$_{q, r, b}$	MWh	*Calculated Metered Energy for Energy Storage Resource Load at Bus*—The calculated ~~energy metered by the Settlement Meter which measures~~ Non-WSL ESR Charging Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
NMSAMTTOT$_{gsc}$	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
WSLAMTTOT$_{q, r, p}$	$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.
CLRAMTTOT$_{q, r, p}$	$	*CLR Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for CLR Load for each 15-minute Settlement Interval.
ESRNWSLAMTTOT$_{q, r, p}$	$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.
NMRTETOT$_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
GSPLITPER$_{q, r, gsc, p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource, ~~or~~ a ~~Controllable Load Resource~~CLR that is not an ALR, or a CLR that is part of an ESR, that is located at the Facility with net metering.
gsc	none	A generation site code.
b	none	An Electrical Bus.

[NPRR1014: Replace paragraph (2) above with the following upon system implementation:]

(2) The payment or charge to each QSE for Energy Imbalance Service at a Resource Node Settlement Point for a given 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMT}_{q,p} = (-1) * \{\sum_{gsc}(\sum_{r}(\mathbf{RESREV}_{q,r,gsc,p})) + (\sum_{r}\mathbf{WSLAMTTOT}_{q,r,p}) + (\sum_{r}\mathbf{CLRAMTTOT}_{q,r,p}) + (\sum_{r}\mathbf{ESRNWSLAMTTOT}_{q,r,p}) + \mathbf{RTSPP}_{p} * [(\mathbf{SSSK}_{q,p} * 1/4) + (\mathbf{DAEP}_{q,p} * 1/4) + (\mathbf{RTQQEP}_{q,p} * 1/4) - (\mathbf{SSSR}_{q,p} * 1/4) - (\mathbf{DAES}_{q,p} * 1/4) - (\mathbf{RTQQES}_{q,p} * 1/4)]\}$$

Where:

$$\mathrm{RESREV}_{q,r,gsc,p} = \mathrm{GSPLITPER}_{q,r,gsc,p} * \mathrm{NMSAMTTOT}_{gsc}$$

$$\mathrm{RESMEB}_{q,r,gsc,p} = \mathrm{GSPLITPER}_{q,r,gsc,p} * \mathrm{NMRTETOT}_{gsc}$$

$$\mathrm{WSLTOT}_{q,p} = \sum_{r}(\sum_{b}\mathrm{MEBL}_{q,r,b})$$

$$\mathrm{CLRTOT}_{q,p} = \sum_{r}(\sum_{b}\mathrm{MEBCL}_{q,r,b})$$

$$\mathrm{ESRNWSLTOT}_{q,p} = \sum_{r}(\sum_{b}\mathrm{MEBR}_{q,r,b})$$

$$\mathrm{RNIMBAL}_{q,p} = \sum_{gsc}(\sum_{r}\mathrm{RESMEB}_{q,r,gsc,p}) + \mathrm{WSLTOT}_{q,p} + \mathrm{CLRTOT}_{q,p} + \mathrm{ESRNWSLTOT}_{q,p} + (\mathrm{SSSK}_{q,p} * 1/4) + (\mathrm{DAEP}_{q,p} * 1/4) + (\mathrm{RTQQEP}_{q,p} * 1/4) - (\mathrm{SSSR}_{q,p} * 1/4) - (\mathrm{DAES}_{q,p} * 1/4) - (\mathrm{RTQQES}_{q,p} * 1/4)$$

The above variables are defined as follows:

Variable	Unit	Description
$\mathrm{RTEIAMT}_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
$\mathrm{RNIMBAL}_{q,p}$	MWh	*Resource Node Energy Imbalance per QSE per Settlement Point*—The Resource Node volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP_{p}	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
$\mathrm{SSSK}_{q,p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.

DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids, Energy Bid Curves, and bid portion of Energy Bid/Offer Curves~~,~~ at Settlement Point *p*, cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
SSSR $_{q, p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
DAES $_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQES $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
RESREV $_{q, r, gsc, p}$	$	*Resource Share Revenue Settlement Payment*—The Resource share of the total payment to the entire Facility with a net metering arrangement attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
RESMEB $_{q, r, gsc, p}$	MWh	*Resource Share Net Meter Real-Time Energy Total*—The Resource share of the net sum for all Settlement Meters attributed to Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*.
WSLTOT $_{q, p}$	MWh	*WSL Total*—The total WSL energy metered by the Settlement Meters which measure WSL for the QSE *q* at Settlement Point *p*.
CLRTOT $_{q, p}$	MWh	*CLR Load Total*—The total energy metered by the Settlement Meters which measures CLR Load for the QSE *q* at Settlement Point *p*.
ESRNWSLTOT $_{q, p}$	MWh	*ESR Non-WSL Total*—The total energy metered by the Settlement Meters which measure~~s~~ Non-WSL ESR Charging Load for the QSE *q* at Settlement Point *p*.
MEBL $_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBCL $_{q, r, b}$	MWh	*Calculated Metered Energy for CLR Load at Bus*—The calculated CLR Load, adjusted for Unaccounted For Energy (UFE), for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBR $_{q, r, b}$	MWh	~~*Adjusted*~~*Calculated Metered Energy for Energy Storage Resource Load at Bus* - The calculated ~~energy metered by the Settlement Meter which measures~~ Non-WSL ESR Charging Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
NMSAMTTOT $_{gsc}$	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
CLRAMTTOT $_{q, r, p}$	$	*CLR Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for CLR Load for each 15-minute Settlement Interval.
WSLAMTTOT $_{q, r, p}$	$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.

ESRNWSLAMTTOT $_{q, r, p}$	$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.
NMRTETOT $_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
GSPLITPER $_{q, r, gsc, p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a net metering arrangement. GSPLITPER is calculated by taking the Supervisory Control and Data Acquisition (SCADA) values (GSSPLITSCA) for a particular Generation Resource or ESR *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
q	none	A QSE.
p	none	A Resource Node Settlement Point.
r	none	A Generation Resource, a CLR that is not an ALR, or ESR that is located at the Facility with net metering.
gsc	none	A generation site code.
b	none	An Electrical Bus.

(3) For a facility with Settlement Meters that measure CLR (that is not an ALR) or ESR Load, the total payment or charge for CLR (that is not an ALR) or ESR Load is calculated for a QSE, CLR (that is not an ALR) or ESR, and Settlement Point for each 15-minute Settlement Interval.

The WSL is settled as follows:

$$\mathbf{WSLAMTTOT}_{q, r, p} = \sum_{b} (\mathbf{RTRMPRESR}_{b} * \mathbf{MEBL}_{q, r, b})$$

The Non-WSL ESR Charging Load is settled as follows:

$$\mathbf{ESRNWSLAMTTOT}_{q, r, p} = \sum_{b} (\mathbf{RTRMPRESR}_{b} * \mathbf{MEBR}_{q, r, b})$$

Where:

$MEBR_{q, r, b}$ = $MEBRFG_{q, r, b}$ + $MEBRSG_{q, r, b}$

The total Non-WSL ESR Charging Load is included in the Real-Time Adjusted Meter Load (AML) per QSE.

Where the price for Settlement Meter is determined as follows:

$$\mathbf{RTRMPRESR}_{b} = \mathbf{Max}\ [-\$251, (\sum_{y} (\mathbf{RNWFL}_{b, y} * \mathbf{RTLMP}_{b, y}) + \mathbf{RTRSVPOR} + \mathbf{RTRDP})]$$

The CLR Load is settled as follows:

$CLRAMTTOT_{q,r,p} = \sum_{b} (RTRMPRCLR_b * MEBCL_{q,r,b})$

Where:

$MEBCL_{q,r,b} = MEBCLFG_{q,r,b} + MEBCLSG_{q,r,b}$

The total CLR Load is included in the Real-Time AML per QSE.

Where the price for Settlement Meter is determined as follows:

$RTRMPRCLR_b = Max [-\$251, (\sum_{y} (RNWFL_{b,y} * RTLMP_{b,y}) + RTRSVPOR + RTRDP)]$

Where the weighting factor for the Electrical Bus associated with the meter is:

$RNWFL_{b,y} = [Max (0.001, \sum_{r} BP_{r,y}) * TLMP_y] /$

$[\sum_{y} Max (0.001, \sum_{r} BP_{r,y}) * TLMP_y]$

Where:

$RTRSVPOR = \sum_{y} (RNWF_y * RTORPA_y)$

$RTRDP = \sum_{y} (RNWF_y * RTORDPA_y)$

$RNWF_y = TLMP_y / \sum_{y} TLMP_y$

The summation is over all CLR (that is not an ALR) or ESR Load *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.

The above variables are defined as follows:

Variable	Unit	Description
$RTLMP_{b,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
$TLMP_y$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.

Variable	Unit	Description
RTORPA $_y$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA $_y$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
MEBL $_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at ~~b~~Bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBR $_{q, r, b}$	MWh	*Calculated Metered Energy for Energy Storage Resource Load at Bus* - The calculated ~~energy metered by the Settlement Meter which measures~~ Non-WSL ESR Charging Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBRFG $_{q, r, b}$	MWh	*Adjusted Metered Energy for Energy Storage Resource Load supplied from the grid at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load supplied from the grid that is adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBRSG $_{q, r, b}$	MWh	*Metered Energy for Energy Storage Resource Load supplied from co-located generation with Net Metering arrangement, at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load supplied from the co-located generation with Net Metering arrangement. This is not adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBCL $_{q, r, b}$	MWh	*Calculated Metered Energy for CLR Load at Bus* - The calculated CLR Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBCLFG $_{q, r, b}$	MWh	*Adjusted Metered Energy for CLR Load supplied from the grid at Bus (Calculated)*—The portion of energy metered by the Settlement Meter which measures CLR Load supplied from the grid that is adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.

Variable	Unit	Description
MEBCLSG$_{q, r, b}$	MWh	*Metered Energy for CLR Load supplied from co-located generation with Net Metering arrangement, at Bus (Calculated)*—The portion of energy metered by the Settlement Meter which measures CLR Load supplied from the co-located generation with Net Metering arrangement. This is not adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
WSLAMTTOT$_{q, r, p}$	$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.
CLRAMTTOT$_{q, r, p}$	$	*CLR Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for CLR Load for each 15-minute Settlement Interval.
ESRNWSLAMTTOT$_{q, r, p}$	$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.
RNWFL$_{b, y}$	none	*Net meter Weighting Factor per interval for the Energy Metered as Energy Storage Resource Load or CLR Load*—The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*, for the ESR Load associated with an ESR or CLR Load associated with a CLR that is not an ALR. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
RTRMPRESR$_{b}$	$/MWh	*Real-Time Price for the Energy Metered as Energy Storage Resource Load at bus*—The Real-Time price for the Settlement Meter which measures ESR Load at Electrical Bus *b*, for the 15-minute Settlement Interval.
RTRMPRCLR$_{b}$	$/MWh	*Real-Time Price for the CLR Energy Metered at bus*—The Real-Time price for the Settlement Meter which measures CLR Load at Electrical Bus *b*, for the 15-minute Settlement Interval.
BP$_{r, y}$	MW	*Base Point per Resource per interval* - The Base Point of Resource *r*, for the SCED interval *y*.
q	none	A QSE.
gsc	none	A generation site code.
r	none	The Controllable Load Resource that is not an ALR, including a CLR that is part of an ESR.
p	none	A Resource Node Settlement Point.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

[NPRR1010 and NPRR1014: Replace applicable portions of paragraph (3) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]

(3) For a facility with Settlement Meters that measure CLR (that is not an ALR) or ESR Load, the total payment or charge for CLR (that is not an ALR) or ESR Load is calculated for a QSE, CLR (that is not an ALR) or ESR, and Settlement Point for each 15-minute Settlement Interval.

The WSL is settled as follows:

$$\mathbf{WSLAMTTOT}_{q,r,p} = \sum_{b} (\mathbf{RTRMPRESR}_{b} * \mathbf{MEBL}_{q,r,b})$$

The Non-WSL ESR Charging Load is settled as follows:

$$\mathbf{ESRNWSLAMTTOT}_{q,r,p} = \sum_{b} (\mathbf{RTRMPRESR}_{b} * \mathbf{MEBR}_{q,r,b})$$

Where:

$MEBR_{q,r,b}$ = $MEBRFG_{q,r,b}$ + $MEBRSG_{q,r,b}$

The total Non-WSL ESR Charging Load is included in the Real-Time Adjusted Meter Load (AML) per QSE.

Where the price for Settlement Meter is determined as follows:

$$\mathbf{RTRMPRESR}_{b} = \mathbf{Max}\ [-\$251, (\sum_{y} (\mathbf{RNWFL}_{b,y} * \mathbf{RTLMP}_{b,y}) + \mathbf{RTRDP})]$$

The CLR Load is settled as follows:

$$\mathbf{CLRAMTTOT}_{q,r,p} = \sum_{b} (\mathbf{RTRMPRCLR}_{b} * \mathbf{MEBCL}_{q,r,b})$$

Where:

$MEBCL_{q,r,b}$ = $MEBCLFG_{q,r,b}$ + $MEBCLSG_{q,r,b}$

The total CLR Load is included in the Real-Time AML per QSE.

Where the price for Settlement Meter is determined as follows:

$$\mathbf{RTRMPRCLR}_{b} = \mathbf{Max}\ [-\$251, (\sum_{y} (\mathbf{RNWFL}_{b,y} * \mathbf{RTLMP}_{b,y}) + \mathbf{RTRDP})]$$

Where the weighting factor for the Electrical Bus associated with the meter is:

$$\mathbf{RNWFL}_{b,y} = [\mathbf{Max}\ (0.001, \mathbf{ABS}(\sum_{y} \mathbf{Min}(0, \mathbf{BP}_{r,y}))) * \mathbf{TLMP}_{y}] /$$

$$[\sum_{y} \mathbf{Max}\ (0.001, \mathbf{ABS}(\sum_{y} \mathbf{Min}(0, \mathbf{BP}_{r,y}))) * \mathbf{TLMP}_{y}]$$

Where:

$$RTRDP = \sum_{y} (RNWF_{y} * RTRDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The summation is over all CLR (that is not an ALR) or ESR Load *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.

The above variables are defined as follows:

Variable	Unit	Description
$RTLMP_{b,y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
$TLMP_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_{y}$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy* —The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Real-Time Reliability Deployment price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$MEBL_{q,r,b}$	MWh	*Metered Energy for Wholesale Storage Load at ~~b~~Bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$MEBCL_{q, r, b}$	MWh	*Calculated Metered Energy for CLR Load at Bus* - The calculated CLR Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$MEBCLFG_{q, r, b}$	MWh	*Adjusted Metered Energy for CLR Load supplied from the grid at Bus (Calculated)*—The portion of energy metered by the Settlement Meter which measures CLR Load supplied from the grid that is adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
$MEBCLSG_{q, r, b}$	MWh	*Metered Energy for CLR Load supplied from co-located generation with Net Metering arrangement, at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures CLR Load supplied from the co-located generation with Net Metering arrangement. This is not adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.

MEBR $_{q, r, b}$	MWh	*Calculated Metered Energy for Energy Storage Resource Load at Bus* - The calculated~~energy metered by the Settlement Meter which measures~~ Non-WSL ESR Charging Load, adjusted for UFE, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBRFG $_{q, r, b}$	MWh	*Adjusted Metered Energy for Energy Storage Resource Load supplied from the grid at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load supplied from the grid that is adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
MEBRSG $_{q, r, b}$	MWh	*Metered Energy for Energy Storage Resource Load supplied from co-located generation with Net Metering arrangement, at Bus (Calculated)* —The portion of energy metered by the Settlement Meter which measures Non-WSL ESR Charging Load supplied from the co-located generation with Net Metering arrangement. This is not adjusted for losses, for the 15-minute Settlement Interval represented as a negative value, for the QSE *q*, Resource *r*, at bus *b*.
WSLAMTTOT $_{q, r, p}$	$	*Wholesale Storage Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for WSL for each 15-minute Settlement Interval.
CLRAMTTOT $_{q, r, p}$	$	*CLR Load Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for CLR Load for each 15-minute Settlement Interval.
ESRNWSLAMTTOT $_{q, r, p}$	$	*Energy Storage Resource Non-WSL Settlement*—The total payment or charge to QSE *q*, Resource *r*, at Settlement Point *p*, for Non-WSL ESR Charging Load for each 15-minute Settlement Interval.
RNWFL $_{b, y}$	none	*Net meter Weighting Factor per interval for the Energy Metered as Energy Storage Resource Load or CLR Load* —The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*, for the ESR Load associated with an ESR or for the CLR Load associated with a CLR that is not an ALR. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
RTRMPRESR $_{b}$	$/MWh	*Real-Time Price for the Energy Metered as Energy Storage Resource Load at bus*—The Real-Time price for the Settlement Meter which measures ESR Load at Electrical Bus *b*, for the 15-minute Settlement Interval.
RTRMPRCLR $_{b}$	$/MWh	*Real-Time Price for the CLR Energy Metered at bus*—The Real-Time price for the Settlement Meter which measures CLR Load at Electrical Bus *b*, for the 15-minute Settlement Interval.
BP $_{r, y}$	MW	*Base Point per Resource per interval* - The Base Point of Resource *r*, for the SCED interval *y*.
q	none	A QSE.
gsc	none	A generation site code.
r	none	A~~n~~ CLR (that is not an ALR) or an ESR.
p	none	A Resource Node Settlement Point.

y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

(4) The total payment or charge to a Facility with a net metering arrangement for each 15-minute Settlement Interval shall be calculated as follows:

$$\mathbf{NMRTETOT}_{gsc} = \mathbf{Max}\ (0, (\sum_{b} (\mathbf{MEB}_{gsc, b} + \mathbf{MEBC}_{gsc, b})))$$

If $NMRTETOT_{gsc} = 0$ for a 15-minute Settlement Interval, then

The Load that is not WSL is included in the Real-Time AML per QSE.

Otherwise, when $NMRTETOT_{gsc} > 0$ for a 15-minute Settlement Interval, then

$$\mathbf{NMSAMTTOT}_{gsc} = \sum_{b} [(\mathbf{RTRMPR}_{b} * \mathbf{MEB}_{gsc, b}) + (\mathbf{RTRMPR}_{b} * \mathbf{MEBC}_{gsc, b})]$$

Where the price for Settlement Meter is determined as follows:

$$\mathbf{RTRMPR}_{b} = \mathbf{Max}\ [-\$251, (\sum_{y} (\mathbf{RNWF}_{b, y} * \mathbf{RTLMP}_{b, y}) + \mathbf{RTRSVPOR} + \mathbf{RTRDP})]$$

Where the weighting factor for the Electrical Bus associated with the meter is:

$$\mathbf{RNWF}_{b, y} = [\mathbf{Max}\ (0.001, \sum_{r} \mathbf{BP}_{r, y}) * \mathbf{TLMP}_{y}] / [\sum_{y} \mathbf{Max}\ (0.001, \sum_{r} \mathbf{BP}_{r, y}) * \mathbf{TLMP}_{y}]$$

Where:

$$RTRSVPOR = \sum_{y} (RNWF_{y} * RTORPA_{y})$$

$$RTRDP = \sum_{y} (RNWF_{y} * RTORDPA_{y})$$

$$RNWF_{y} = TLMP_{y} / \sum_{y} TLMP_{y}$$

The summation is over all Resources *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.

The above variables are defined as follows:

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Variable	Unit	Description
NMRTETOT $_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
NMSAMTTOT $_{gsc}$	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
RTRMPR $_{b}$	$/MWh	*Real-Time Price for the Energy Metered for each Resource meter at bus*—The Real-Time price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval.
MEB $_{gsc, b}$	MWh	*Metered Energy at ~~b~~Bus*— The metered energy by the Settlement Meter which is not upstream from another Settlement Meter which measures CLR (that is not an ALR) or ESR Load for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy withdrawn.
RTRSVPOR	$/MWh	*Real-Time Reserve Price for On-Line Reserves*—The Real-Time Reserve Price for On-Line Reserves for the 15-minute Settlement Interval.
RTORPA $_{y}$	$/MWh	*Real-Time On-Line Reserve Price Adder per interval*—The Real-Time On-Line Reserve Price Adder for the SCED interval *y*.
RTRDP	$/MWh	*Real-Time On-Line Reliability Deployment Price* —The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time On-Line Reliability Deployment Price Adder.
RTORDPA $_{y}$	$/MWh	*Real-Time On-Line Reliability Deployment Price Adder* —The Real-Time Price Adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
RNWF $_{y}$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
RTLMP $_{b, y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
TLMP $_{y}$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
RNWF $_{b, y}$	none	*Net meter Weighting Factor per interval*—The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
BP $_{r, y}$	MW	*Base Point per Resource per interval*—The Base Point of Resource *r*, for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MEBC $_{gsc, b}$	MWh	*Metered Energy at ~~b~~Bus (Calculated)*— The calculated energy for the 15-minute Settlement Interval for a Settlement Meter which is upstream from another Settlement Meter which measures CLR (that is not an ALR) or ESR Load. A positive value represents energy produced, and a negative value represents energy withdrawn. This is not adjusted for losses and UFE.
gsc	none	A generation site code.

Variable	Unit	Description
r	none	A Generation Resource that is located at the Facility with net metering.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

[NPRR1010 and NPRR1014: Replace applicable portions of paragraph (4) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010; or upon system implementation for NPRR1014:]

(4) The total payment or charge to a Facility with a net metering arrangement for each 15-minute Settlement Interval shall be calculated as follows:

$$\mathbf{NMRTETOT}_{gsc} = \mathbf{Max}\left(0, \left(\sum_{b} \left(\mathbf{MEB}_{gsc,b} + \mathbf{MEBC}_{gsc,b}\right)\right)\right)$$

If $NMRTETOT_{gsc} = 0$ for a 15-minute Settlement Interval, then

The Load that is not WSL is included in the Real-Time AML per QSE.

Otherwise, when $NMRTETOT_{gsc} > 0$ for a 15-minute Settlement Interval, then

$$\mathbf{NMSAMTTOT}_{gsc} = \sum_{b} \left[\left(\mathbf{RTRMPR}_{b} * \mathbf{MEB}_{gsc,b}\right) + \left(\mathbf{RTRMPR}_{b} * \mathbf{MEBC}_{gsc,b}\right)\right]$$

Where the price for Settlement Meter is determined as follows:

$$\mathbf{RTRMPR}_{b} = \mathbf{Max}\left[-\$251, \left(\sum_{y} \left(\mathbf{RNWF}_{b,y} * \mathbf{RTLMP}_{b,y}\right) + \mathbf{RTRDP}\right)\right]$$

Where the weighting factor for the Electrical Bus associated with the meter is:

$$\mathbf{RNWF}_{b,y} = \left[\mathbf{Max}\left(0.001, \sum_{r} \mathbf{Max}\left(0, \mathbf{BP}_{r,y}\right)\right) * \mathbf{TLMP}_{y}\right] / \left[\sum_{y} \mathbf{Max}\left(0.001, \sum_{r} \mathbf{Max}\left(0, \mathbf{BP}_{r,y}\right)\right) * \mathbf{TLMP}_{y}\right]$$

Where:

$$RTRDP = \sum_{y} \left(RNWF_{y} * RTRDPA_{y}\right)$$

$$RNWF_y = TLMP_y / \sum_{y} TLMP_y$$

The summation is over all Resources *r* associated to the individual meter. The determination of which Resources are associated to an individual meter is static and based on the normal system configuration of the generation site code, *gsc*.

The above variables are defined as follows:

Variable	Unit	Description
$NMRTETOT_{gsc}$	MWh	*Net Meter Real-Time Energy Total*—The net sum for all Settlement Meters included in generation site code *gsc*. A positive value indicates an injection of power to the ERCOT System.
$NMSAMTTOT_{gsc}$	$	*Net Metering Settlement*—The total payment or charge to a generation site with a net metering arrangement.
$RTRMPR_b$	$/MWh	*Real-Time Price for the Energy Metered for each Resource meter at bus*—The Real-Time price for the Settlement Meter at Electrical Bus *b*, for the 15-minute Settlement Interval.
$MEB_{gsc, b}$	MWh	*Metered Energy at ~~b~~Bus*—The metered energy by the Settlement Meter which is not upstream from another Settlement Meter which measures CLR (that is not an ALR) or ESR Load for the 15-minute Settlement Interval. A positive value represents energy produced, and a negative value represents energy withdrawn.
RTRDP	$/MWh	*Real-Time Reliability Deployment Price for Energy*—The Real-Time price for the 15-minute Settlement Interval, reflecting the impact of reliability deployments on energy prices that is calculated from the Real-Time Reliability Deployment Price Adder for Energy.
$RTRDPA_y$	$/MWh	*Real-Time Reliability Deployment Price Adder for Energy*—The Real-Time price adder that captures the impact of reliability deployments on energy prices for the SCED interval *y*.
$RNWF_y$	none	*Resource Node Weighting Factor per interval*—The weight used in the Resource Node Settlement Point Price calculation for the portion of the SCED interval *y* within the Settlement Interval.
$RTLMP_{b, y}$	$/MWh	*Real-Time Locational Marginal Price at bus per interval*—The Real-Time LMP for the meter at Electrical Bus *b*, for the SCED interval *y*.
$TLMP_y$	second	*Duration of SCED interval per interval*—The duration of the SCED interval *y*.
$RNWF_{b, y}$	none	*Net meter Weighting Factor per interval*—The weight factor used in net meter price calculation for meters in Electrical Bus *b*, for the SCED interval *y*. The weighting factor used in the net meter price calculation shall not be recalculated after the fact due to revisions in the association of Resources to Settlement Meters.
$BP_{r, y}$	MW	*Base Point per Resource per interval*—The Base Point of Resource *r*, for the SCED interval *y*. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

$MEBC_{gsc, b}$	MWh	*Metered Energy at ~~b~~Bus (Calculated)* — The calculated energy for the 15-minute Settlement Interval for a Settlement Meter which is upstream from another Settlement Meter which measures CLR (that is not an ALR) or ESR Load. A positive value represents energy produced, and a negative value represents energy withdrawn. This is not adjusted for losses and UFE.
gsc	none	A generation site code.
r	none	A Generation Resource or ESR that is located at the Facility with net metering.
y	none	A SCED interval in the 15-minute Settlement Interval. The summation is over the total number of SCED runs that cover the 15-minute Settlement Interval.
b	none	An Electrical Bus.

(5) The Generation Resource SCADA Splitting Percentage for each Resource within a net metering arrangement for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{GSPLITPER}_{q, r, gsc, p} = \mathbf{GSSPLITSCA}_{r} / \sum_{r} \mathbf{GSSPLITSCA}_{r}$$

The above variables are defined as follows:

Variable	Unit	Definition
$GSPLITPER_{q, r, gsc, p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. GSPLITPER is calculated by taking the SCADA values (GSSPLITSCA) for a particular Generation Resource *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
$GSSPLITSCA_{r}$	MWh	*Generation Resource SCADA Net Real Power provided via Telemetry*—The net real power provided via telemetry per Resource within the net metering arrangement, integrated for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
gsc	none	A generation site code.
r	none	A Generation Resource that is located at the Facility with net metering.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

[NPRR1014: Replace paragraph (5) above with the following upon system implementation:]

(5) The Generation Resource or ESR SCADA Splitting Percentage for each Resource within a net metering arrangement for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{GSPLITPER}_{q,\ r,\ gsc,\ p} = \mathbf{GSSPLITSCA}_{r} / \sum_{r} \mathbf{GSSPLITSCA}_{r}$$

The above variables are defined as follows:

Variable	Unit	Definition
GSPLITPER $_{q, r, gsc, p}$	none	*Generation Resource SCADA Splitting Percentage*—The generation allocation percentage for Resource *r* that is part of a generation site code *gsc* for the QSE *q* at Settlement Point *p*. GSPLITPER is calculated by taking the SCADA values (GSSPLITSCA) for a particular Generation Resource or ESR *r* that is part of a net metering configuration and dividing by the sum of all SCADA values for all Resources that are included in the net metering configuration for each interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
GSSPLITSCA $_{r}$	MWh	*Generation Resource SCADA Net Real Power provided via Telemetry*—The net real power provided via telemetry per Resource within the net metering arrangement, integrated for the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is the Combined Cycle Train.
gsc	none	A generation site code.
r	none	A Generation Resource or ESR that is located at the Facility with net metering.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

(6) The total net payments and charges to each QSE for Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMTQSETOT}_{q} = \sum_{p} \mathbf{RTEIAMT}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
RTEIAMTQSETOT $_{q}$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Resource Node Settlement Points for the 15-minute Settlement Interval.
RTEIAMT $_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Resource Node Settlement Point.

6.6.3.2 Real-Time Energy Imbalance Payment or Charge at a Load Zone

(1) The payment or charge to each QSE for Energy Imbalance Service is calculated based on the Real-Time Settlement Point Price for the following amounts at a particular Load Zone Settlement Point:

(a) The amount of its Self-Schedules with sink specified at the Settlement Point; plus

(b) The amount of its DAM Energy Bids cleared in the DAM at the Settlement Point; plus

(c) The amount of its Energy Trades at the Settlement Point where the QSE is the buyer; minus

(d) The amount of its Self-Schedules with source specified at the Settlement Point; minus

(e) The amount of its energy offers cleared in the DAM at the Settlement Point; minus

(f) The amount of its Energy Trades at the Settlement Point where the QSE is the seller; minus

(g) Its Adjusted Meter Load (AML) at the Settlement Point excluding Non-WSL ESR Charging Load and CLR Load of a CLR (that is not an ALR); plus

(h) The aggregated generation of its Settlement Only Transmission Self-Generators (SOTSGs) at the Settlement Point. SOTSG sites will be represented as a single unit in the ERCOT Settlement system.; plus

(i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG). SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.; plus

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

(i) The aggregated generation of its Settlement Only Distribution Generators (SODGs) and Settlement Only Transmission Generators (SOTGs) that have elected to retain Load Zone pricing in accordance with Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS). SODG, SOTG,

Settlement Only Distribution Energy Storage System (SODESS), and Settlement Only Transmission Energy Storage System (SOTESS) sites will be represented as a single unit in the ERCOT Settlement system~~.~~; plus

(j) The aggregated generation of its Energy Storage System (ESS) SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SODG or SOTG nameplate capacity, as confirmed by an affidavit submitted by the Resource Entity for the site. SODG and SOTG sites will be represented as a single unit in the ERCOT Settlement system.

(2) The payment or charge to each QSE for Energy Imbalance Service at a Load Zone for a given 15-minute Settlement Interval is calculated as follows:

$$RTEIAMT_{q,p} = (-1) * \{[RTSPP_p * [(SSSK_{q,p} * ¼) + (DAEP_{q,p} * ¼) + (RTQQEP_{q,p} * ¼) - (SSSR_{q,p} * ¼) - (DAES_{q,p} * ¼) - (RTQQES_{q,p} * ¼)]] + [RTSPPEW_p * (RTMGSOGZ_{q,p} - (RTAML_{q,p} - RTAMLCLRL_{q,p} - RTAMLESRNW_{q,p}))]\}$$

[NPRR995: Replace the formula "$RTEIAMT_{q,p}$" above with the following upon system implementation:]

$$RTEIAMT_{q,p} = (-1) * \{[RTSPP_p * [(SSSK_{q,p} * ¼) + (DAEP_{q,p} * ¼) + (RTQQEP_{q,p} * ¼) - (SSSR_{q,p} * ¼) - (DAES_{q,p} * ¼) - (RTQQES_{q,p} * ¼)]] + [RTSPPEW_p * (RTMGSOGZ_{q,p} - (RTAML_{q,p} - RTAMLCLRL_{q,p} - RTAMLESRNW_{q,p} - RTAMLNWSOL_{q,p}))]\}$$

And

$$LZIMBAL_{q,p} = (SSSK_{q,p} * ¼) + (DAEP_{q,p} * ¼) + (RTQQEP_{q,p} * ¼) - (SSSR_{q,p} * ¼) - (DAES_{q,p} * ¼) - (RTQQES_{q,p} * ¼) - (RTAML_{q,p} - RTAMLCLRL_{q,p} - RTAMLESRNW_{q,p}) + RTMGSOGZ_{q,p}$$

[NPRR995: Replace the formula "$LZIMBAL_{q,p}$" above with the following upon system implementation:]

$$LZIMBAL_{q,p} = (SSSK_{q,p} * ¼) + (DAEP_{q,p} * ¼) + (RTQQEP_{q,p} * ¼) - (SSSR_{q,p} * ¼) - (DAES_{q,p} * ¼) - (RTQQES_{q,p} * ¼) -$$

(RTAML $_{q, p}$ – RTAMLCLRL $_{q, p}$ – RTAMLESRNW $_{q, p}$ – RTAMLNWSOL $_{q, p}$) + RTMGSOGZ $_{q, p}$

The above variables are defined as follows:

Variable	Unit	Description
RTEIAMT $_{q, p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The payment or charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPP $_{p}$	$/MWh	*Real-Time Settlement Point Price per Settlement Point*—The Real-Time Settlement Point Price at Settlement Point *p*, for the 15-minute Settlement Interval.
LZIMBAL $_{q, p}$	MWh	*Load Zone Energy Imbalance per QSE per Settlement Point*—The Load Zone volumetric imbalance for QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
RTSPPEW $_{p}$	$/MWh	*Real-Time Settlement Point Price Energy-Weighted*—The Real-Time Settlement Point Price at the Settlement Point *p*, for the 15-minute Settlement Interval that is weighted by the State Estimated Load for the Load Zone of each SCED interval within the 15-minute Settlement Interval.
RTAML $_{q, p}$	MWh	*Real-Time Adjusted Metered Load per QSE per Settlement Point*—The sum of the AML at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval.
RTAMLCLRL $_{q, p}$	MWh	*Real-Time Adjusted Metered Load for CLR Load per QSE per Settlement Point*—The sum of the AML for the CLR Load from CLRs (that are not ALRs) at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.
RTAMLESRNW $_{q, p}$	MWh	*Real-Time Adjusted Metered Load for ESR Non-WSL per QSE per Settlement Point*—The sum of the AML for the Non-WSL ESR Charging Load at the Electrical Buses that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.
[NPRR995: Insert the variable "RTAMLNWSOL $_{q, p}$" below upon system implementation:]		
RTAMLNWSOL $_{q, p}$	MWh	*Real-Time Adjusted Metered Load for Non-WSL Settlement Only Charging Load per QSE per Settlement Point*—The sum of the AML for the Non-WSL Settlement Only Charging Load for the SODESS or SOTESS site that are included in Settlement Point *p* represented by QSE *q* for the 15-minute Settlement Interval, represented as a positive value.
SSSK $_{q, p}$	MW	*Self-Schedule with Sink at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with sink at Settlement Point *p*, for the 15-minute Settlement Interval.
DAEP $_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The QSE *q*'s DAM Energy Bids and Energy Bid Curves at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
RTQQEP $_{q, p}$	MW	*Real-Time QSE-to-QSE Energy Purchase per QSE per Settlement Point*—The amount of MW bought by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.

Variable	Unit	Description
$SSSR_{q,p}$	MW	*Self-Schedule with Source at Settlement Point per QSE per Settlement Point*—The QSE *q*'s Self-Schedule with source at Settlement Point *p*, for the 15-minute Settlement Interval.
$DAES_{q,p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The QSE *q*'s energy offers at Settlement Point *p* cleared in the DAM, for the hour that includes the 15-minute Settlement Interval.
$RTQQES_{q,p}$	MW	*Real-Time QSE-to-QSE Energy Sale per QSE per Settlement Point*—The amount of MW sold by QSE *q* through Energy Trades at Settlement Point *p*, for the 15-minute Settlement Interval.
$RTMGSOGZ_{q,p}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by SOTSGs represented by QSE *q* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for ESS SODGs and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that have opted out of nodal pricing pursuant to Section 6.6.3.8 will also be included in this value.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

(3) The total net payments and charges to each QSE for Energy Imbalance Service at all Load Zones for the 15-minute Settlement Interval is calculated as follows:

$$\mathbf{RTEIAMTQSETOT}_{q} = \sum_{p} \mathbf{RTEIAMT}_{q,p}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RTEIAMTQSETOT_{q}$	$	*Real-Time Energy Imbalance Amount QSE Total per QSE*—The total net payments and charges to QSE *q* for Real-Time Energy Imbalance Service at all Load Zone Settlement Points for the 15-minute Settlement Interval.
$RTEIAMT_{q,p}$	$	*Real-Time Energy Imbalance Amount per QSE per Settlement Point*—The charge to QSE *q* for Real-Time Energy Imbalance Service at Settlement Point *p*, for the 15-minute Settlement Interval.
q	none	A QSE.
p	none	A Load Zone Settlement Point.

6.6.5.1 Resource Base Point Deviation Charge

(1) A QSE for a Generation Resource or Controllable Load Resource shall pay a Base Point Deviation Charge if the Resource did not follow Dispatch Instructions and Ancillary Service deployments within defined tolerances, except when the Dispatch Instructions and Ancillary Service deployments violate the Resource Parameters. The Base Point Deviation Charge does not apply to Generation Resources when Adjusted Aggregated Base Point (AABP) is less than the Resource's average telemetered LSL, the QSE's Generation Resources are operating in Constant Frequency Control (CFC) mode, or any time during the Settlement Interval when the telemetered Resource Status is set to ONTEST or STARTUP. The Base Point Deviation Charge does not apply to a

Controllable Load Resource if the computed Base Point is equal to the snapshot of its telemetered power consumption for all SCED runs during the Settlement Interval or any time during the Settlement Interval when the telemetered Resource Status is set to OUTL or ONTEST. The desired output from a Generation Resource or desired consumption from a Controllable Load Resource during a 15-minute Settlement Interval is calculated as follows:

$$AABP_{q, r, p, i} = AVGBP_{q, r, p, i} + AVGREG_{q, r, p, i}$$

Where:

$$AVGBP_{q, r, p, i} = \sum_{y} (AVGBP5M_{q, r, p, i, y}) / 3$$

$$AVGREG_{q, r, p, i} = \sum_{y} (AVGREG5M_{q, r, p, i, y}) / 3$$

$$AVGREG5M_{q, r, p, i, y} = (AVGREGUP5M_{q, r, p, i, y} - AVGREGDN5M_{q, r, p, i, y})$$

The above variables are defined as follows:

Variable	Unit	Definition
$AABP_{q, r, p, i}$	MW	*Adjusted Aggregated Base Point per QSE per Settlement Point per Resource*—The aggregated Base Point adjusted for Ancillary Service deployments of Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AABP is calculated for the Combined Cycle Train considering all SCED Dispatch Instructions to any Combined Cycle Generation Resources within the Combined Cycle Train.
$AVGBP_{q, r, p, i}$	MW	*Average Base Point per QSE per Settlement Point per Resource*—The average of the five-minute clock interval Base Points over the 15-minute Settlement Interval *i* for Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*.
$AVGBP5M_{q, r, p, i, y}$	MW	*Average five-minute clock interval Base Point per QSE per Settlement Point per Resource*—The average Base Point for the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p*, for the five-minute clock interval *y* within the 15-minute Settlement Interval *i*. The time-weighted average of the linearly ramped Base Points in a five-minute clock interval *y*. The linearly ramped Base Point is calculated every four seconds such that it ramps from its initial value to the SCED Base Point over a five-minute clock interval *y*. The initial value of the linearly ramped Base Point will be the four second value of the previous linearly ramped Base Point at the time the new SCED Base Point is received into the ERCOT Energy Management System (EMS). The linear ramp is recalculated each time that a new Base Point is received from SCED. AVGBP5M is equal to the ABP value calculated for use in Generation Resource Energy Deployment Performance (GREDP) or the ABP value calculated for use in the Controllable Load Resource Energy Deployment Performance (CLREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics.

Variable	Unit	Definition
AVGREG $_{q, r, p, i}$	MW	*Average Regulation Instruction per QSE per Settlement Point per Resource* —The average of the five-minute clock interval *y* Regulation Instruction Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* over the 15-minute Settlement Interval *i*.
AVGREG5M $_{q, r, p, i, y}$	MW	*Total Average five-minute clock interval Regulation Instruction per QSE per Settlement Point per Resource*—The total amount of regulation that the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* should have produced based on Load Frequency Control (LFC) deployment signals over the five-minute clock interval *y* within the 15-minute Settlement Interval *i*.
AVGREGUP5M $_{q, r, p, i, y}$	MW	*Average Regulation Instruction Up per QSE per Settlement Point per Resource*—The amount of Regulation Up Service (Reg-Up) that the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* should have produced based on LFC deployment signals over the five-minute clock interval *y* within the 15-minute Settlement Interval *i*.
AVGREGDN5M $_{q, r, p, i, y}$	MW	*Average Regulation Instruction Down per QSE per Settlement Point per Resource*—The amount of Regulation Down Service (Reg-Down) that the Generation Resource or Controllable Load Resource *r* represented by QSE *q* at Settlement Point *p* should have produced based on LFC deployment signals over the five-minute clock interval *y* within the 15-minute Settlement Interval *i*.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource or Controllable Load Resource.
i	None	A 15-minute Settlement Interval
y	none	A five-minute clock interval in the Settlement Interval.

[NPRR963, NPRR1010, and NPRR1014: Replace applicable portions of Section 6.6.5.1 above with the following upon system implementation for NPRR963 or NPRR1014; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.5.1 Resource Set Point Deviation Charge

(1) A QSE for a Generation Resource, ESR, or Controllable Load Resource shall pay a Set Point Deviation Charge if the Resource did not follow UDSPs within defined tolerances, except when the UDSPs violate the Resource Parameters.

(2) The desired output from a Generation Resource, ESR, or Controllable Load Resource during a 15-minute Settlement Interval is calculated as follows:

$$\mathbf{AASP}_{q, r, p, i} = \sum_{y} \mathbf{(AVGSP5M}_{q, r, p, i, y}\mathbf{)} / 3$$

The above variables are defined as follows:

Variable	Unit	Definition
$AASP_{q, r, p, i}$	MW	*Average Aggregated Set Point per QSE per Settlement Point per Resource*—The average of the Average Five Minute Clock Interval Set Point (AVGSP5M) of Resource *r* represented by QSE *q* at Settlement Point *p*, for the 15-minute Settlement Interval *i*. Where for a Combined Cycle Train, AASP is calculated for the Combined Cycle Train considering all UDSPs to any Combined Cycle Generation Resources within the Combined Cycle Train.
$AVGSP5M_{q, r, p, i, y}$	MW	*Average Five Minute Clock Interval Set Point per QSE per Settlement Point per Resource* –The time-weighted average of the Updated Desired Set Point (UDSP) that Resource *r* for QSE *q* at Settlement Point *p* should have produced, for the five-minute clock interval *y* within the 15-minute Settlement Interval *i*. AVGSP5M is equal to the ASP value calculated for use in Generation Resource Energy Deployment Performance (GREDP), Controllable Load Resource Energy Deployment Performance (CLREDP), or Energy Storage Resource Energy Deployment Performance (ESREDP), as described in Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource, ESR, or Controllable Load Resource.
i	none	A 15-minute Settlement Interval
y	none	A five-minute clock interval in the Settlement Interval.

6.6.5.3 Resources Exempt from Deviation Charges

(1) Resource Base Point Deviation Charges do not apply to the following:

(a) Reliability Must-Run (RMR) Units;

(b) Dynamically Scheduled Resources (DSRs) (except as described in Section 6.4.2.2, Output Schedules for Dynamically Scheduled Resources);

(c) Qualifying Facilities (QFs) that do not submit an Energy Offer Curve for the Settlement Interval;

(d) Quick Start Generation Resources (QSGRs) during the 15-minute Settlement Interval after the start of the first SCED interval in which the QSGR is deployed; or

(e) Settlement Intervals in which Emergency Base Points were issued to the Resource.

[NPRR863, NPRR963, NPRR1000, NPRR1010, NPRR1014, and NPRR1046: Replace applicable portions of Section 6.6.5.3 above with the following upon system implementation for NPRR863, NPRR963, or NPRR1014; upon system implementation of NPRR1000 for NPRR1000 and

NPRR1046; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1010:]

6.6.5.6 Resources Exempt from Deviation Charges

Commented [CP12]: Please note NPRR1245 also proposes revisions to this section.

(1) Set Point Deviation Charges do not apply to any QSE for the 15-minute Settlement Interval during the following events:

(a) Responsive Reserve (RRS) was manually deployed by ERCOT;

(b) ERCOT Contingency Reserve Service (ECRS) was deployed; or

(c) ERCOT System Frequency deviation is both greater than +0.05 Hz and less than -0.05 Hz within the same Settlement Interval.

(2) Set Point Deviation Charges do not apply to the QSE for the Resource for the 15-minute Interval for the following:

(a) The deviation of the Resource over the 15-minute Settlement Interval is in a direction that contributes to frequency corrections that resolve an ERCOT System frequency deviation and ERCOT System frequency deviation is greater than +/-0.05 Hz at any time during the 15-minute Settlement Interval;

(b) The Resource is a Reliability Must-Run (RMR) Unit;

(c) Emergency Base Points were issued to the Resource; or

(d) Resource is operating in Constant Frequency Control (CFC) mode.

(3) In addition to the exemptions listed in paragraph (1) and (2) of this Section, Set Point Deviation Charges do not apply to the QSE for a Generation Resource for the 15-minute Settlement Interval for the following:

(a) AASP is less than the Resource's average telemetered LSL;

(b) The Generation Resource is telemetering a status of ONTEST or STARTUP anytime during the Settlement Interval;

(c) Qualifying Facilities (QFs) that do not submit an Energy Offer Curve prior to the end of the Adjustment Period for the Settlement Interval;

(d) Quick Start Generation Resources (QSGRs) during the 15-minute Settlement Interval after the start of the first SCED interval in which the QSGR is deployed; or

(e) The flag signifying that an IRR has received a Base Point below the HDL used by SCED or the IRR has been instructed not to exceed its Base Point is not set in all SCED intervals within the 15-minute Settlement Interval. For IRR Groups, the flag signifying that an IRR has received a Base Point below the HDL used by SCED or the

IRR has been instructed not to exceed its Base Point is not set in all SCED intervals within the 15-minute Settlement Interval for any of the IRRs within the IRR Group.

(4) In addition to the exemptions listed in paragraph (1) and (2) of this Section, Set Point Deviation Charges do not apply to the QSE for the Controllable Load Resource for the 15-minute Settlement Interval if the following occur:

(a) The UDSP is equal to the snapshot of its telemetered power consumption for all SCED runs during the Settlement Interval; or

(b) The Controllable Load Resource is telemetering a status of OUTL or ONTEST anytime during the Settlement Interval.

(5) In addition to the exemptions listed in paragraph (1) and (2) of this Section, Set Point Deviation Charges do not apply to the QSE for the ESR for the 15-minute Settlement Interval if the following occur:

(a) The ESR is telemetering a status of ONTEST anytime during the Settlement Interval; or

(b) The AASP is less than its average telemetered LSL.

7.9.1.3 Minimum and Maximum Resource Prices

(1) For purposes of Section 7.9.1, Day-Ahead CRR Payments and Charges, Settlements data published to the Market Information System (MIS) Secure Area shall include the association of the Resource Category for each Generation Resource and identify Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs). The following prices specified in paragraphs (2) and (3) below are used in the CRR hedge value calculation for CRRs settled in the DAM.

[NPRR1014: Replace paragraph (1) above with the following upon system implementation:]

(1) For purposes of Section 7.9.1, Day-Ahead CRR Payments and Charges, Settlements data published to the Market Information System (MIS) Secure Area shall include the association of the Resource Category for each Generation Resource, identify Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs), and identify Energy Storage Resources (ESRs). The following prices specified in paragraphs (2) and (3) below are used in the CRR hedge value calculation for CRRs settled in the DAM.

(2) Minimum Resource Prices of source Settlement Points are:

$$\mathbf{MINRESPR}_{j} = \mathbf{Min}\ (\mathbf{MINRESRPR}_{j,r})_{r}$$

Where:

Minimum Resource Prices for Resources located at source Settlement Points (**MINRESRPR** $_{j, r}$) are:

(a) Nuclear = -$20.00/MWh;

(b) Hydro = -$20.00/MWh;

(c) Coal and Lignite = $0.00/MWh;

(d) Combined Cycle greater than 90 MW = Fuel Index Price (FIP) * 5 MMBtu/MWh;

(e) Combined Cycle less than or equal to 90 MW = FIP * 6 MMBtu/MWh;

(f) Gas -Steam Supercritical Boiler = FIP * 6.5 MMBtu/MWh;

(g) Gas Steam Reheat Boiler = FIP * 7.5 MMBtu/MWh;

(h) Gas Steam Non-Reheat or Boiler without Air-Preheater = FIP * 10.5 MMBtu/MWh;

(i) Simple Cycle greater than 90 MW = FIP * 10 MMBtu/MWh;

(j) Simple Cycle less than or equal to 90 MW = FIP * 11 MMBtu/MWh;

(k) Diesel = FIP * 12 MMBtu/MWh;

(l) Wind = -$35/MWh;

(m) PhotoVoltaic (PV) = -$10;

(n) Reliability Must-Run (RMR) Resource = RMR contract price Energy Offer Curve at Low Sustained Limit (LSL); ~~and~~

(o) CLR = $100/MWh; and

[NPRR1014: Insert item (~~o~~p) below upon system implementation and renumber accordingly:]

(~~o~~p) ESR = -$20/MWh; and

(~~o~~p) Other = -$20/MWh~~;~~.

The above variables are defined as follows:

Variable	Unit	Definition
MINRESPR $_j$	$/MWh	*Minimum Resource Price for source*—The lowest Minimum Resource Price for the Resources located at the source Settlement Point *j*.
MINRESRPR $_j$	$/MWh	*Minimum Resource Price for Resource*—The Minimum Resource Price for the Resources located at the source Settlement Point *j*.
r	none	A Generation Resource or CLR that is not an ALR located at the source Settlement Point *j*. ***[NPRR1014: Replace the definition above with the following upon system implementation:]*** A Generation Resource, CLR that is not an ALR, or ESR located at the source Settlement Point *j*.
j	none	A source Settlement Point.

(3) Maximum Resource Prices of sink Settlement Points are:

MAXRESPR $_k$ = **Max (MAXRESRPR** $_{k, r}$ **)** $_r$

Where:

Maximum Resource Prices for Resources located at sink Settlement Points **(MAXRESRPR** $_{k, r}$ **)** are:

(a) Nuclear = $15.00/MWh;

(b) Hydro = $10.00/MWh;

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

(d) Combined Cycle greater than 90 MW = FIP * 9 MMBtu/MWh;

(e) Combined Cycle less than or equal to 90 MW = FIP * 10 MMBtu/MWh;

(f) Gas -Steam Supercritical Boiler = FIP * 10.5 MMBtu/MWh;

(g) Gas Steam Reheat Boiler = FIP * 11.5 MMBtu/MWh;

(h) Gas Steam Non-Reheat or Boiler without Air-Preheater = FIP * 14.5 MMBtu/MWh;

(i) Simple Cycle greater than 90 MW = FIP * 14 MMBtu/MWh;

(j) Simple Cycle less than or equal to 90 MW = FIP * 15 MMBtu/MWh;

(k) Diesel = FIP * 16 MMBtu/MWh;

(l) Wind = $0/MWh;

(m) PV = $0/MWh;

(n) RMR Resource = RMR contract price Energy Offer Curve at High Sustained Limit (HSL); ~~and~~

(o) CLR = SWCAP; and

[NPRR1014: Insert item (po) below upon system implementation and renumber accordingly:]

(~~o~~p) ESR = $100/MWh; and

(~~o~~p) Other = $100/MWh.

The above variables are defined as follows:

Variable	Unit	Definition
MAXRESPR $_k$	$/MWh	*Maximum Resource Price for source*—The highest Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
MAXRESRPR $_k$	$/MWh	*Maximum Resource Price for Resource*—The Maximum Resource Price for the Resources located at the sink Settlement Point *k*.
r	none	A Generation Resource or CLR that is not an ALR located at the sink Settlement Point *k*. ***[NPRR1014: Replace the definition above with the following upon system implementation:]*** A Generation Resource, CLR that is not an ALR, or ESR located at the sink Settlement Point *k*.
k	none	A sink Settlement Point.

7.9.3.1 DAM Congestion Rent

Commented [CP13]: Please note NPRR1245 also proposes revisions to this section.

(1) The DAM congestion rent is calculated as the sum of the following payments and charges:

(a) The total of payments to all QSEs for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves, calculated under Section 4.6.2.1, Day-Ahead Energy Payment;

(b) The total of charges to all QSEs for cleared DAM Energy Bids and Energy Bid Curves, calculated under Section 4.6.2.2, Day-Ahead Energy Charge; and

(c) The total of charges or payments to all QSEs for PTP Obligation bids cleared in the DAM, calculated under Section 4.6.3, Settlement for PTP Obligations Bought in DAM.

(d) The total of charges to all QSEs for PTP Obligation with Links to an Option bids cleared in the DAM, calculated under Section 4.6.3.

(2) The DAM congestion rent for a given Operating Hour is calculated as follows:

DACONGRENT = DAESAMTTOT + DAEPAMTTOT + DARTOBLAMTTOT + DARTOBLLOAMTTOT

Where:

$$DAESAMTTOT = \sum_{q} DAESAMTQSETOT_{q}$$

$$DAEPAMTTOT = \sum_{q} DAEPAMTQSETOT_{q}$$

$$DARTOBLAMTTOT = \sum_{q} DARTOBLAMTQSETOT_{q}$$

$$DARTOBLLOAMTTOT = \sum_{q} DARTOBLLOAMTQSETOT_{q}$$

The above variables are defined as follows:

Variable	Unit	Definition
DACONGRENT	$	*Day-Ahead Congestion Rent*—The congestion rent collected in the DAM for the hour.
DAESAMTTOT	$	*Day-Ahead Energy Sale Amount Total*—The total payment to all QSEs for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves, for the hour.
DAEPAMTTOT	$	*Day-Ahead Energy Purchase Amount Total*—The total charge to all QSEs for ~~cleared~~ DAM Energy Bids and Energy Bid Curves, cleared in the DAM, for the hour.
DARTOBLAMTTOT	$	*Day-Ahead Real-Time Obligation Amount Total*—The net total charge or payment to all QSEs for cleared PTP Obligation bids in the DAM for the hour.
DARTOBLLOAMTTOT	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount Total*—The net total charge to all QSEs for charge to QSE *q* for a PTP Obligation with Links to an Option Bid cleared in the DAM with the source *j* and the sink *k*, for the hour.
$DAESAMTQSETOT_{q}$	$	*Day-Ahead Energy Sale Amount QSE Total per QSE*—The total payment to QSE *q* for cleared DAM energy offers, whether through Three-Part Supply Offers or through DAM Energy-Only Offer Curves, for the hour. See item (2) of Section 4.6.2.1.
$DAEPAMTQSETOT_{q}$	$	*Day-Ahead Energy Purchase Amount QSE Total per QSE*—The total charge to QSE *q* for ~~cleared~~ DAM Energy Bids and Energy Bid Curves, cleared in the DAM, for the hour. See item (2) of Section 4.6.2.2.
$DARTOBLAMTQSETOT_{q}$	$	*Day-Ahead Real-Time Obligation Amount QSE Total per QSE*—The total charge or payment to QSE *q* for PTP Obligation Bids cleared in the DAM for the hour. See item (2) of Section 4.6.3.

Variable	Unit	Definition
$DARTOBLLOAMTQSETOT_q$	$	*Day-Ahead Real-Time Obligation with Links to an Option Amount QSE Total per QSE*—The net total charge to QSE q for all its PTP Obligation with Links to ~~an~~ Option Bids cleared in the DAM for the hour.
q	none	A QSE.

8.1.1.1 Ancillary Service Qualification and Testing

Commented [CP14]: Please note NPRR1246 also proposes revisions to this section.

(1) Each QSE and the Resource providing Ancillary Service must meet qualification criteria to operate satisfactorily with ERCOT. ERCOT shall use the Ancillary Service qualification and testing program that is approved by TAC and included in the Operating Guides. Each QSE for the Resources that it represents may only provide Ancillary Services on those Resources for which it has met the qualification criteria.

(2) General capacity testing must be used to verify a Resource's Net Dependable Capability. Qualification tests allow the Resource and QSE to demonstrate the minimum capabilities necessary to deploy an Ancillary Service.

(3) A Resource may be provisionally qualified for a period of 90 days and may be eligible to participate as a Resource providing Ancillary Service. Resources that have installed the appropriate equipment with verifiable testing data may be provisionally qualified as providers of Ancillary Service.

(4) A Load Resource may be provisionally qualified for a period of 90 days to participate as a Resource providing Ancillary Service, if the Load Resource is metered with an Interval Data Recorder (IDR) to ERCOT's reasonable satisfaction. A Load Resource providing Ancillary Service in Real-Time must meet the following requirements:

(a) Electric Service Identifier (ESI ID) registration of Load Resources providing Ancillary Service by the QSE; and

(b) Load Resource telemetry is installed and tested between QSE and ERCOT.

(5) Provisional qualification as described herein may be revoked by ERCOT at any time for any non-compliance with provisional qualification requirements.

(6) For those Settlement Intervals during which a Generation Resource or Load Resource behind the ~~Generation~~ Resource Node is engaged in testing in accordance with this Section, the provisions of Section 6.6.5, ~~Generation Resource~~ Base ~~-~~Point Deviation Charge, will not apply to the Resource being tested beginning with the Settlement Interval immediately preceding the Settlement Interval in which ERCOT issues a Dispatch Instruction that begins the test and continuing until the end of the Settlement Interval in which the test completes. During the same Settlement Intervals for the testing period, the Generation Resource Energy Deployment Performance (GREDP) and Controllable Load Resource Energy Deployment Performance (CLREDP) calculated in accordance with Section 8.1.1.4.1, Regulation Service and Generation

Resource/Controllable Load Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, will not apply.

(7) ERCOT may reduce the amount a Resource may contribute toward Ancillary Service if it determines unsatisfactory performance of the Resource as defined in Section 8.1.1, QSE Ancillary Service Performance Standards.

(8) To maintain qualification with ERCOT to provide RRS or ECRS, each Load Resource, excluding Controllable Load Resources, will be subject to a Load interruption test at a date and time determined by ERCOT and known only to ERCOT and the affected Transmission Service Provider (TSP), to verify the ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, within ten minutes of the receipt of the ERCOT Dispatch Instruction by the Load Resource's QSE, the Load Resource's response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:

(a) The Resource's Responsibility for ECRS and RRS; or

(b) The requested MW deployment.

The requested MW deployment will be the sum of the Resource's Responsibility for ECRS and RRS and the telemetered additional capacity between the net power consumption and the Low Power Consumption (LPC). If a Load Resource has responded to an actual ERCOT Dispatch Instruction in compliance with (a) and (b) above in the rolling 365-day period, ERCOT will use that response in lieu of a Load interruption test. If a Load Resource has not responded to an ERCOT Dispatch Instruction in compliance with (a) and (b) above, either in a deployment event or a Load interruption test, in any rolling 365-day period, it is subject to a Load interruption test by ERCOT. QSEs may request to have individual Load Resources aggregated for the purposes of Load interruption tests. All performance evaluations will apply on an individual Resource basis.

(9) ERCOT may revoke the Ancillary Service qualification of any Load Resource, excluding Controllable Load Resources, for failure to comply with the required performance standards, based on the evaluation it performed under paragraph (4) of Section 8.1.1.4.2, Responsive Reserve Service Energy Deployment Criteria, or under paragraph (1)(b) of Section 8.1.1.4.4, ERCOT Contingency Reserve Service Energy Deployment. Specifically, if a Load Resource that is providing RRS or ECRS fails to respond with at least 95% of its Ancillary Service Resource Responsibility for RRS or ECRS within ten minutes of an ERCOT Dispatch Instruction, that response shall be considered a failure. Two Load Resource performance failures, either in a deployment event or a Load interruption test, within any rolling 365-day period shall result in disqualification of that Load Resource. After six months of disqualification, the Load Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Load Resource successfully passes a new Load interruption test as specified in this Section 8.1.1.1.

(10) To maintain qualification with ERCOT to provide RRS from Fast Frequency Response (FFR), each Resource will be subject to an FFR qualification test at a date and time determined by ERCOT and known only to ERCOT and the affected TSP as applicable, to verify the ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, within ten minutes of the receipt of the ERCOT Dispatch Instruction by the Resource's QSE, the Resource's response shall not be less than 95% of the requested MW deployment, nor more than 105% of the lesser of the following:

(a) The Resource's Ancillary Service Resource Responsibility for RRS; or

(b) The MW deployment.

The requested MW deployment for Resources capable of FFR will be the sum of the Resource's Ancillary Service Resource Responsibility for RRS and the additional capacity between the telemetered High Sustained Limit (HSL) and the telemetered Low Sustained Limit (LSL). If a Resource has responded to an actual event in compliance with items (a) and (b) above in the rolling 365-day period, ERCOT will use that response in lieu of an FFR test. If a Resource has not responded to an ERCOT Dispatch Instruction in compliance with items (a) and (b) above, in either a deployment event or an FFR test, in any rolling 365-day period, it is subject to an FFR test by ERCOT. All performance evaluations will apply on an individual Resource basis.

(11) ERCOT may revoke the Ancillary Service qualification of any Resource providing FFR if that Resource has two Resource performance failures, either in a manual deployment event or a frequency triggered event, within any rolling 365-day period. A performance failure is defined as a response less than 95% or more than 105% of the Resource's Ancillary Service Resource Responsibility for RRS within 15 cycles of a triggering event or within ten minutes of an ERCOT Dispatch Instruction. This shall result in disqualification of that Resource. After six months of disqualification, a Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Resource successfully passes a new test as specified in Section 8.1.1.2.1.2, Responsive Reserve Qualification.

[NPRR963 and NPRR1011: Replace applicable portions of Section 8.1.1.1 above with the following upon system implementation for NPRR963; or upon system implementation of Real-Time Co-Optimization (RTC) project for NPRR1011:]

8.1.1.1 Ancillary Service Qualification and Testing

(1) Each QSE and the Resource providing Ancillary Service must meet qualification criteria to operate satisfactorily with ERCOT. ERCOT shall use the Ancillary Service qualification and testing program that is approved by TAC and included in the Operating Guides. Each QSE for the Resources that it represents may only provide Ancillary Services on those Resources for which it has met the qualification criteria.

(2) General capacity testing must be used to verify a Resource's Net Dependable Capability. Qualification tests allow the Resource and QSE to demonstrate the minimum capabilities necessary to deploy an Ancillary Service.

(3) A Resource may be provisionally qualified for a period of 90 days and may be eligible to participate as a Resource providing Ancillary Service. Resources that have installed the appropriate equipment with verifiable testing data may be provisionally qualified as providers of Ancillary Service.

(4) A Load Resource may be provisionally qualified for a period of 90 days to participate as a Resource providing Ancillary Service, if the Load Resource is metered with an Interval Data Recorder (IDR) to ERCOT's reasonable satisfaction. A Load Resource providing Ancillary Service in Real-Time must meet the following requirements:

(a) Electric Service Identifier (ESI ID) registration of Load Resources providing Ancillary Service by the QSE; and

(b) Load Resource telemetry is installed and tested between QSE and ERCOT.

(5) Provisional qualification as described herein may be revoked by ERCOT at any time for any non-compliance with provisional qualification requirements.

(6) For those Settlement Intervals during which a Generation Resource, Load Resource, or Energy Storage Resource (ESR) behind the ~~Generation~~ Resource Node is engaged in testing in accordance with this Section, the provisions of Section 6.6.5, Set Point Deviation Charge, will not apply to the Resource being tested beginning with the Settlement Interval immediately preceding the Settlement Interval in which ERCOT issues a Dispatch Instruction that begins the test and continuing until the end of the Settlement Interval in which the test completes. During the same Settlement Intervals for the testing period, the Generation Resource Energy Deployment Performance (GREDP), Controllable Load Resource Energy Deployment Performance (CLREDP), or Energy Storage Resource Energy Deployment Performance (ESREDP) calculated in accordance with Section 8.1.1.4.1, Regulation Service and Generation Resource/Controllable Load Resource/Energy Storage Resource Energy Deployment Performance, and Ancillary Service Capacity Performance Metrics, will not apply.

(7) ERCOT may reduce the amount a Resource may contribute toward Ancillary Service if it determines unsatisfactory performance of the Resource as defined in Section 8.1.1, QSE Ancillary Service Performance Standards.

(8) To maintain qualification with ERCOT to provide RRS or ECRS service, each Load Resource, excluding Controllable Load Resources, will be subject to a Load interruption test at a date and time determined by ERCOT and known only to ERCOT and the affected Transmission Service Provider (TSP), to verify the ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, within ten minutes of the receipt of the ERCOT Dispatch Instruction by the Load Resource's QSE, the

Load Resource's response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:

(a) The Resource's ECRS and RRS awards, or

(b) The requested MW deployment.

The requested MW deployment will be the sum of the Resource's ECRS and RRS awards, and the telemetered additional capacity between the net power consumption and the Low Power Consumption (LPC). If a Load Resource has responded to an actual ERCOT Dispatch Instruction in compliance with (a) and (b) above in the rolling 365-day period, ERCOT will use that response in lieu of a Load interruption test. If a Load Resource has not responded to an ERCOT Dispatch Instruction in compliance with (a) and (b) above, either in a deployment event or a Load interruption test, in any rolling 365-day period, it is subject to a Load interruption test by ERCOT. QSEs may request to have individual Load Resources aggregated for the purposes of Load interruption tests. All performance evaluations will apply on an individual Resource basis.

(9) ERCOT may revoke the Ancillary Service qualification of any Load Resource, excluding Controllable Load Resources, for failure to comply with the required performance standards, based on the evaluation it performed under paragraph (5) of Section 8.1.1.4.2, Responsive Reserve Energy Deployment Criteria or under paragraph (1)(c) of Section 8.1.1.4.4, ERCOT Contingency Reserve Service Energy Deployment Criteria. Specifically, if a Load Resource that is providing RRS or ECRS fails to respond with at least 95% of its ECRS or RRS award within ten minutes of an ERCOT Dispatch Instruction, that response shall be considered a failure. Two Load Resource performance failures, either in a deployment event or a Load interruption test, within any rolling 365-day period shall result in disqualification of that Load Resource. After six months of disqualification, the Load Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Load Resource successfully passes a new Load interruption test as specified in this Section 8.1.1.1.

(10) To maintain qualification with ERCOT to provide RRS from Fast Frequency Response (FFR), each Resource will be subject to an FFR qualification test at a date and time determined by ERCOT and known only to ERCOT and the affected TSP as applicable, to verify the ability to respond to an ERCOT Dispatch Instruction. To successfully pass this test, within ten minutes of the receipt of the ERCOT Dispatch Instruction by the Resource's QSE, the Resource's response shall not be less than 95% of the requested MW deployment, nor more than 105% of the lesser of the following:

(a) The Resource's RRS award; or

(b) The MW deployment.

The requested MW deployment for Resources capable of FFR will be the sum of the Resource's RRS award and the additional capacity between the telemetered High Sustained Limit (HSL) and the telemetered Low Sustained Limit (LSL). If a Resource has responded to an actual event in compliance with items (a) and (b) above in the rolling 365-day period, ERCOT will use that response in lieu of an FFR test. If a Resource has not responded to an ERCOT Dispatch Instruction in compliance with items (a) and (b) above, in either a deployment event or an FFR test, in any rolling 365-day period, it is subject to an FFR test by ERCOT. All performance evaluations will apply on an individual Resource basis.

(11) ERCOT may revoke the Ancillary Service qualification of any Resource providing FFR if that Resource has two Resource performance failures, either in a manual deployment event or a frequency triggered event, within any rolling 365-day period. A performance failure is defined as a response less than 95% or more than 105% of the Resource's RRS award within 15 cycles of a triggering event or within ten minutes of an ERCOT Dispatch Instruction. This shall result in disqualification of that Resource. After six months of disqualification, a Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Resource successfully passes a new test as specified in Section 8.1.1.2.1.2, Responsive Reserve Qualification.

8.1.1.4.3 Non-Spinning Reserve Service Energy Deployment Criteria

(1) ERCOT shall, as part of its Ancillary Service deployment procedure under Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment, include all performance metrics for a Resource receiving a Non-Spin recall instruction from ERCOT.

(2) A Non-Spin Dispatch Instruction from ERCOT must respect the minimum runtime of a Generation Resource. After the recall of a Non-Spin Dispatch Instruction, any Generation Resource previously Off-Line providing Non-Spin is allowed to remain On-Line for 30 minutes following the recall. During that time period, the On-Line Generation Resource is treated as if the Non-Spin is being provided.

(3) Control performance during periods in which ERCOT has deployed Non-Spin shall be based on the requirements below and failure to meet any one of these requirements for the greater of one or 5% of Non-Spin deployments during a month shall be reported to the Reliability Monitor as non-compliance:

(a) Within 20 minutes following a deployment instruction, the QSE must update the telemetered Ancillary Service Schedule for Non-Spin for Generation Resources and Controllable Load Resources to reflect the deployment amount.

(b) Off-Line Generation Resources, within 25 minutes following a deployment instruction, must be On-Line with an Energy Offer Curve and the telemetered net generation must be greater than or equal to the Resource's telemetered LSL multiplied by P1 where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating

Hour." The Resource Status that must be telemetered indicating that the Resource has come On-Line with an Energy Offer Curve is ON as described in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria.

(c) If an Off-Line Generation Resource experiences a Startup Loading Failure (excluding those caused by operator error), the Resource may be considered for exclusion from performance non-compliance if the QSE provides to ERCOT the following documentation regarding the incident:

(i) Its generation log documenting the Startup Loading Failure; and

(ii) Equipment failure documentation such as, but not limited to, GADS reports, plant operator logs, work orders, or other applicable information.

(d) For QSEs with Load Resources that are not Controllable Load Resources, 30 minutes following deployment instruction the sum of the QSE's Load Resource response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:

(i) The QSE's award for Non-Spin from Load Resources that are not Controllable Load Resources; or

(ii) The requested MW deployment.

The QSE's portfolio shall maintain this response until recalled.

(e) During periods when the Load level of a Load Resource that is not a Controllable Load Resource providing Non-Spin has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource's actual Load response from its Baseline. "Baseline" capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the difference between the Baseline and the average of the real power consumption data being telemetered to ERCOT over the Settlement Interval for the period beginning 30 minutes after the Dispatch Instruction and ending at the time of recall. The instantaneous response at any point in time during the sustained response period must be no less than 95% and no more than 150% of the Dispatch Instruction.

(4) A Load Resource that is not a Controllable Load Resource providing Non-Spin must return to at least 95% of its Ancillary Service Resource Responsibility for Non-Spin within three hours following a recall instruction unless replaced by another Resource as described below. However, the Load Resource should attempt to return to at least 95% of its Ancillary Service Resource Responsibility for Non-Spin as soon as practical considering process constraints. For a Load Resource that is not a Controllable Load Resource that is unable to return to its Ancillary Service Resource Responsibility within three hours of recall instruction, its QSE may replace the quantity of deficient Non-Spin

capacity within that same three hours using other Resources not previously committed to provide Non-Spin.

(5) ERCOT may revoke the Ancillary Service qualification of any Load Resource that is not a Controllable Load Resource for failure to comply with the required performance standards, based on the evaluation it performed under this Section. Specifically, if a Load Resource that is not a Controllable Load Resource that is providing Non-Spin fails to respond with at least 95% of its Dispatch Instruction for Non-Spin within 30 minutes of an ERCOT Dispatch Instruction, that response shall be considered a failure. Two Load Resource performance failures within any rolling 365-day period shall result in disqualification of that Load Resource. After six months of disqualification, the Load Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Load Resource successfully passes qualification test as specified in Section 8.1.1.1, Ancillary Service Qualification and Testing.

[NPRR1011: Replace Section 8.1.1.4.3 above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

8.1.1.4.3 Non-Spinning Reserve Service Energy Deployment Criteria

(1) ERCOT shall, as part of its Ancillary Service deployment procedure under Section 6.5.7.6.2.3, Non-Spinning Reserve Service Deployment, include all performance metrics for a Resource receiving a Non-Spin recall instruction from ERCOT.

(2) A Non-Spin Dispatch Instruction from ERCOT must respect the minimum runtime of a Generation Resource.

(3) Control performance during periods in which ERCOT has manually deployed Non-Spin shall be based on the requirements below and failure to meet any one of these requirements for the greater of one or 5% of Non-Spin deployments during a month shall be reported to the Reliability Monitor as non-compliance:

(a) Off-Line Generation Resources, within 25 minutes following a deployment instruction, must be On-Line with an Energy Offer Curve and the telemetered net generation must be greater than or equal to the Resource's telemetered LSL multiplied by P1 where P1 is defined in the "ERCOT and QSE Operations Business Practices During the Operating Hour." The Resource Status that must be telemetered indicating that the Resource has come On-Line with an Energy Offer Curve is ON as described in paragraph (5)(b)(i) of Section 3.9.1, Current Operating Plan (COP) Criteria.

(b) If an Off-Line Generation Resource experiences a Startup Loading Failure (excluding those caused by operator error), the Resource may be considered for exclusion from performance non-compliance if the QSE provides to ERCOT the following documentation regarding the incident:

(i) Its generation log documenting the Startup Loading Failure; and

(ii) Equipment failure documentation such as, but not limited to, GADS reports, plant operator logs, work orders, or other applicable information.

(c) Controllable Load Resources must be available to SCED, and must have an ~~Real-Time Market (RTM)~~ Energy Bid Curve and the telemetered net real power consumption must be greater than or equal to the Resource's telemetered LPC.

(d) For QSEs with Load Resources that are not Controllable Load Resources, 30 minutes following deployment instruction, the sum of the QSE's Load Resource response shall not be less than 95% of the requested MW deployment, nor more than 150% of the lesser of the following:

(i) The QSE's award for Non-Spin from Load Resources that are not Controllable Load Resources; or

(ii) The requested MW deployment.

The QSE's portfolio shall maintain this response until recalled.

(e) During periods when the Load level of a Load Resource that is not a Controllable Load Resource providing Non-Spin has been affected by a Dispatch Instruction from ERCOT, the performance of a Load Resource in response to a Dispatch Instruction must be determined by subtracting the Load Resource's actual Load response from its Baseline. "Baseline" capacity is calculated by measuring the average of the real power consumption for five minutes before the Dispatch Instruction if the Load level of a Load Resource had not been affected by a Dispatch Instruction from ERCOT. The actual Load response is the difference between the Baseline and the average of the real power consumption data being telemetered to ERCOT over the Settlement Interval for the period beginning 30 minutes after the Dispatch Instruction and ending at the time of recall. The instantaneous response at any point in time during the sustained response period must be no less than 95% and no more than 150% of the Dispatch Instruction.

(4) Once Non-Spin capacity has been manually deployed by ERCOT, the Resource's Non-Spin capacity shall remain available for dispatch by SCED until ERCOT issues a recall instruction or the Resource has exhausted its ability to maintain the deployed capacity after meeting the requirements of paragraph (2) of Section 8.1.1.3.3, Non-Spinning Reserve Capacity Monitoring Criteria, whichever occurs first.

(5) A Load Resource that is not a Controllable Load Resource providing Non-Spin must return to at least 95% of its Ancillary Service Resource Responsibility for Non-Spin within three hours following a recall instruction unless replaced by another Resource as described below. However, the Load Resource should attempt to return to at least 95% of its Ancillary Service Resource Responsibility for Non-Spin as soon as practical

considering process constraints. For a Load Resource that is not a Controllable Load Resource that is unable to return to its Ancillary Service Resource Responsibility within three hours of recall instruction, its QSE may replace the quantity of deficient Non-Spin capacity within that same three hours using other Resources not previously committed to provide Non-Spin.

(6) ERCOT may revoke the Ancillary Service qualification of any Load Resource that is not a Controllable Load Resource for failure to comply with the required performance standards, based on the evaluation it performed under this Section. Specifically, if a Load Resource that is not a Controllable Load Resource that is providing Non-Spin fails to respond with at least 95% of its Dispatch Instruction for Non-Spin within 30 minutes of an ERCOT Dispatch Instruction, that response shall be considered a failure. Two Load Resource performance failures within any rolling 365-day period shall result in disqualification of that Load Resource. After six months of disqualification, the Load Resource may reapply for qualification provided it submits a corrective action plan to ERCOT that identifies actions taken to correct performance deficiencies and the disqualified Load Resource successfully passes qualification test as specified in Section 8.1.1.1, Ancillary Service Qualification and Testing.

9.14.10 Settlement for Market Participants Impacted by Omitted Procedures or Manual Actions to Resolve the DAM

Commented [CP15]: Please note NPRRs 1235 and 1245 also propose revisions to this section.

(1) A Market Participant that has been directly impacted by an action or omission by ERCOT to resolve the DAM, as described in paragraph (4) of Section 4.1.2, Day-Ahead Process and Timing Deviations, may seek recovery by filing a Settlement and billing dispute as defined in Section 9.14. Where ERCOT determines that the Market Participant seeking recovery has been directly impacted by such ERCOT action or omission, the following provisions apply:

(a) No resettlement of the DAM will occur as a result of a Market Participant's recovery under this Section;

(b) Where a Market Participant's submissions were not cleared in the DAM, ERCOT will establish a set of DAM Energy Bids, DAM Energy Offers, Ancillary Service Offers, Energy Bid Curves, and Point-to-Point (PTP) bids that would have cleared given the settled prices of the DAM;

(c) Startup Costs and minimum energy costs will not be considered for recovery;

(d) For linked offers of energy and Ancillary Services, the available capacity will be allocated to the offers that would have created the greatest value for the Market Participant seeking recovery;

(e) All impacted positions will be summed based on their positive or negative value with respect to Real-Time prices;

Day-Ahead Energy Sales Impact

$$DAMSQSEAMT_q = (-1) * \sum_p ((DASPP_p - RTSPP_p) * (1/4) * DAES_{q,p})$$

Day-Ahead Energy Purchase Impact

$$DAMPQSEAMT_q = (-1) * \sum_p ((RTSPP_p - DASPP_p) * (1/4) * DAEP_{q,p})$$

Day-Ahead Ancillary Services Sales Impact

$$DAMASQSEAMT_q = (-1) * \sum_r (((MCPCRU_{DAM} - RUOPR_{q,r,DAM}) * PCRUR_{q,r,DAM})$$
$$+ ((MCPCRD_{DAM} - RDOPR_{q,r,DAM}) * PCRDR_{q,r,DAM})$$
$$+ ((MCPCRR_{DAM} - RROPR_{q,r,DAM}) * PCRRR_{q,r,DAM})$$
$$+ ((MCPCECR_{DAM} - ECRSOPR_{q,r,DAM}) * PCECRR_{q,r,DAM})$$
$$+ ((MCPCNS_{DAM} - NSOPR_{q,r,DAM}) * PCNSR_{q,r,DAM}))$$

Day-Ahead Point-to-Point Obligation Impact

$$DAMRTPTPQSEAMT_q = (-1) * \sum_j \sum_k ((RTOBLPR_{(j,k)} - DAOBLPR_{(j,k)}) * RTOBL_{q,(j,k)})$$

Where:

$$RTOBLPR_{(j,k)} = \sum_{i=1}^{4} (RTSPP_{(k,i)} - RTSPP_{(j,i)}) / 4$$
$$DAOBLPR_{(j,k)} = DASPP_k - DASPP_j$$

(f) If any RUC short charges occur for any Operating Hour involved in a Market Participant's recovery under this Section, ERCOT will evaluate the Market Participant's revised position to determine if the Market Participant is entitled to a refund, or should be charged for RUC short charge;

(g) Any resulting charge or payment to the Market Participant will be invoiced using a miscellaneous Invoice, but allocated with the method outlined in paragraphs (2) through (4) of Section 9.19.1, Default Uplift Invoices.

The above variables are defined as follows:

Variable	Unit	Definition
$DAMSQSEAMT_q$	$	*Day-Ahead Market Energy Sales Amount by QSE*—The sum of the DAM Energy Sales positions compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval.
$DAMPQSEAMT_q$	$	*Day-Ahead Market Energy Purchases Amount by QSE*—The sum of the DAM Energy purchases compared to Real-Time results, for the QSE *q*, for the 15-minute Settlement Interval.

$DAMASQSEAMT_q$	$	*Day-Ahead Market Ancillary Service Amount by QSE*—The sum of the DAM Ancillary Service awarded amounts compared to Real-Time results, for the QSE *q*, for the hour.
$DAMRTPTPQSEAMT_q$	$	*Day-Ahead Market Real-Time Point-to-Point Obligation Amount by QSE*—The sum of the PTP Obligation bids cleared in the DAM compared to Real-Time results, for the QSE *q*, for the hour.
$DASPP_p$	$/MWh	*Day-Ahead Settlement Point Price per Settlement Point*—The DAM Settlement Point Price at Settlement Point *p*, for the hour.
$RTOBL_{q, (j, k)}$	MW	*Real-Time Obligation per QSE per pair of source and sink*—The total MW of QSE *q*'s PTP Obligation bids that would have cleared in the DAM and settled in Real-Time for the source *j,* and the sink *k*, for the hour.
$RTSPP_p$	$/MWh	*Real-Time Settlement Point Price*—The Real-Time Settlement Point Price at the Settlement Point for the 15-minute Settlement Interval within the hour.
$DAES_{q, p}$	MW	*Day-Ahead Energy Sale per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s Three-Part Supply Offers that would have cleared in the DAM and DAM Energy-Only Offer Curves that would have cleared in the DAM at Settlement Point *p*, for the hour.
$DAEP_{q, p}$	MW	*Day-Ahead Energy Purchase per QSE per Settlement Point*—The total amount of energy represented by QSE *q*'s DAM Energy Bids and Energy Bid Curves that would have cleared in the DAM at Settlement Point *p*, for the hour.
$PCRUR_{q, r, DAM}$	MW	*Procured Capacity for Regulation Up from Resource per QSE per Resource in DAM*—The Regulation Up Service (Reg-Up) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PCRDR_{q, r, DAM}$	MW	*Procured Capacity for Regulation Down from Resource per QSE per Resource in DAM*—The Regulation Down Service (Reg-Down) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PCRRR_{q, r, DAM}$	MW	*Procured Capacity for Responsive Reserve from Resource per QSE per Resource in DAM*—The Responsive Reserve (RRS) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PCNSR_{q, r, DAM}$	MW	*Procured Capacity for Non-Spinning Reserve from Resource per QSE per Resource in DAM*—The Non-Spinning Reserve (Non-Spin) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$PCECRR_{q, r, DAM}$	MW	*Procured Capacity for ERCOT Contingency Reserve Service from Resource per QSE per Resource in DAM*—The ERCOT Contingency Reserve Service (ECRS) capacity quantity that would have been awarded to QSE *q* in the DAM for Resource *r*, for the hour. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RUOPR_{q, r, DAM}$	$/MW per hour	*Regulation Up Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted Reg-Up Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$RDOPR_{q, r, DAM}$	$/MW per hour	*Regulation Down Offer Price*—The offer price for Resource *r* represented by QSE *q,* for the impacted Reg-Down Ancillary Service Offers. Where for a Combined Cycle

		Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
RROPR $_{q, r, DAM}$	$/MW per hour	*Responsive Reserve Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted RRS Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
ECRSOPR $_{q, r, DAM}$	$/MW per hour	*ERCOT Contingency Reserve Service Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted ECRS Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
NSOPR $_{q, r, DAM}$	$/MW per hour	*Non-Spinning Reserve Offer Price*—The offer price for Resource *r* represented by QSE *q*, for the impacted Non-Spin Ancillary Service Offers. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
MCPCRU $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Regulation Up in DAM*—The DAM Market Clearing Price for Capacity (MCPC) for Reg-Up, for the hour.
MCPCRD $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Regulation Down in DAM*—The DAM MCPC for Reg-Down, for the hour.
MCPCRR $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Responsive Reserve in DAM*—The DAM MCPC for RRS, for the hour.
MCPCNS $_{DAM}$	$/MW per hour	*Market Clearing Price for Capacity for Non-Spinning Reserve in DAM*—The DAM MCPC for Non-Spin, for the hour.
MCPCECR DAM	$/MW per hour	*Market Clearing Price for Capacity for ERCOT Contingency Reserve Service in DAM*—The DAM MCPC for ECRS, for the hour.
DAOBLPR $_{(j, k)}$	$/MWh	*Day-Ahead Obligation Price per pair of source and sink*—The DAM clearing price of a PTP Obligation bid with the source *j*, and the sink *k*, for the hour.
RTOBLPR $_{(j, k)}$	$/MWh	*Real-Time Obligation Price per pair of source and sink*—The Real-Time calculated price of a PTP Obligation bid with the source *j*, and the sink *k*, for the 15 minute period.
q	none	A QSE.
r	none	A Resource.
i	none	A 15-minute Settlement Interval.
k	none	A sink Settlement Point.
p	none	A Settlement Point.
j	none	A source Settlement Point.

9.17.1 Billing Determinant Data Elements

(1) ERCOT shall calculate and provide to Market Participants on the ERCOT website the following data elements annually to be used by TSPs and DSPs as billing determinants for transmission access service. This data must be provided by December 1 of each year. This calculation must be made under the requirements of P.U.C. SUBST. R. 25.192, Transmission Service Rates. ERCOT shall use the most recent aggregate data produced by the ERCOT Settlement system to perform these calculations.

(a) The 4-Coincident Peak (4-CP) for each DSP and External Load Serving Entity (ELSE), as applicable;

(b) The ERCOT average 4-CP;

(c) The average 4-CP for each DSP and ELSE, as applicable, coincident to the ERCOT average 4-CP.

(2) ERCOT average 4-CP is defined as the average of the coincidental MW peaks occurring during the months of June, July, August, and September.

(3) Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity's (NOIE's) Load - actual DC Tie exports - Wholesale Storage Load (WSL) - Controllable Load Resource (CLR) Load supplied by co-located generation at sites with net metering arrangement (that is not an Aggregate Load Resource (ALR)) - Non-WSL charging Load supplied by co-located generation at sites with net metering arrangement.

[NPRR995: Replace paragraph (3) above with the following upon system implementation:]

(3) Coincidental MW peak is defined as the highest monthly Settlement Interval 15-minute MW peak for the entire ERCOT Transmission Grid as calculated per the following formula: The sum of all net energy produced by Generation Resources + Settlement Only Generators (SOGs) + Settlement Only Energy Storage Systems (SOESSs) + Block Load Transfers (BLTs) from ERCOT to another Control Area that have been registered for Settlement purposes + actual Direct Current Tie (DC Tie) imports - BLTs to ERCOT from another Control Area that are not reflected in a Non-Opt-In Entity's (NOIE's) Load - actual DC Tie exports - Wholesale Storage Load (WSL) – portion of Controllable Load Resource (CLR) Load (that is not an ALR) as well as Non-WSL charging Load supplied by co-located generation at sites with net metering arrangement.

(4) Any difference between the coincidental MW peak (converted to MWh) and the ERCOT Settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, portion of CLR Load (that is not an ALR) as well as Non-WSL charging Load supplied by co-located generation at sites with net metering arrangement, and WSL, shall be allocated amongst all DSPs and ELSEs that are included in the ERCOT 4-CP Report on a pro rata basis as per the formula below:

$LTDSP\_4CP_{tdsp} = (PLTDSP4CPLRS_{tdsp} * NLADJ) + PLTDSP4CP_{tdsp}$

The above variables are defined as follows:

Variable	Unit	Definition
$LTDSP\_4CP_{tdsp}$	MWh	*Load by TDSP for 4-CP* - The load for each DSP and ELSE coincident to the coincidental MW peak adjusted for NLADJ

Variable	Unit	Definition
PLTDSP4CPLRS $_{tdsp}$	%	*Preliminary Load by TDSP for 4-CP Load Ratio Share* - The Load Ratio Share (LRS) for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
NLADJ	MWh	*Native Load Adjustment* - The difference between the coincidental MW peak (converted to MWh) and the ERCOT settlement volumes, excluding DC Tie exports, BLTs to ERCOT from another Control Area that are not reflected in a NOIE's Load, portion of CLR Load that is not an ALR as well as Non-WSL charging Load supplied by co-located generation at sites with net metering arrangement, and WSL
PLTDSP4CP $_{tdsp}$	MWh	*Preliminary Load by TDSP for 4CP* - The Load for each DSP and ELSE coincident to the coincidental MW peak prior to adjusting for NLADJ
tdsp	None	A DSP or ELSE

9.19.1 Default Uplift Invoices

Commented [CP16]: Please note NPRR1246 also proposes revisions to this section.

(1) ERCOT shall collect the total short-pay amount for all Settlement Invoices for a month, less the total payments expected from a payment plan, from Qualified Scheduling Entities (QSEs) and CRR Account Holders. ERCOT must pay the funds it collects from payments on Default Uplift Invoices to the Entities previously short-paid. ERCOT shall notify those Entities of the details of the payment.

(2) Each Counter-Party's share of the uplift is calculated using the best available Settlement data for each Operating Day in the month prior to the month in which the default occurred (the "reference month"), and is calculated as follows:

$$\mathbf{DURSCP}_{cp} = \mathbf{TSPA} * \mathbf{MMARS}_{cp}$$

Where:

$$MMARS_{cp} = MMA_{cp} / MMATOT$$

$$MMA_{cp} = \text{Max} \{ \sum_{mp} (URTMG_{mp} + URTDCIMP_{mp} + USOGTOT_{mp}),$$

$$\sum_{mp} (URTAML_{mp} + UWSLTOT_{mp}),$$

$$\sum_{mp} URTQQES_{mp},$$

$$\sum_{mp} URTQQEP_{mp},$$

$$\sum_{mp} UDAES_{mp},$$

$$\sum_{mp} UDAEP_{mp},$$

$$\sum_{mp} (URTOBL_{mp} + URTOBLLO_{mp}),$$

$$\sum_{mp} (UDAOPT_{mp} + UDAOBL_{mp} + UOPTS_{mp} + UOBLS_{mp}),$$

$$\sum_{mp} (UOPTP_{mp} + UOBLP_{mp})\}$$

[NPRR995, NPRR1012, and NPRR1201: Replace applicable portions of the formula "MMA $_{cp}$" above with the following upon system implementation for NPRR995 or NPRR1201; or upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1012:]

$$\begin{aligned}MMA_{cp} = \text{Max} \{ & \sum_{mp} (URTMG_{mp} + URTDCIMP_{mp} + USOGTOT_{mp}), \\ & \sum_{mp} (URTAML_{mp} + UWSLTOT_{mp} + USOCLTOT_{mp}), \\ & \sum_{mp} URTQQES_{mp}, \\ & \sum_{mp} URTQQEP_{mp}, \\ & \sum_{mp} UDAES_{mp}, \\ & \sum_{mp} UDAEP_{mp}, \\ & \sum_{mp} (URTOBL_{mp} + URTOBLLO_{mp}), \\ & \sum_{mp} (UDAOPT_{mp} + UDAOBL_{mp}), \\ & \sum_{mp} UDAASOAWD_{mp}\}\end{aligned}$$

$$MMATOT = \sum_{cp} (MMA_{cp})$$

Where:

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

$URTDCIMP_{mp} = \sum_{p, i} (RTDCIMP_{mp, p, i}) / 4$

$URTAML_{mp} = \max(0, \sum_{p, i} (RTAML_{mp, p, i}))$

$URTQQES_{mp} = \sum_{p, i} (RTQQES_{mp, p, i}) / 4$

$URTQQEP_{mp} = \sum_{p, i} (RTQQEP_{mp, p, i}) / 4$

$UDAES_{mp} = \sum_{p, h} (DAES_{mp, p, h})$

$UDAEP_{mp} = \sum_{p, h} (DAEP_{mp, p, h})$

$URTOBL_{mp} = \sum_{(j, k), h} (RTOBL_{mp, (j, k), h})$

$URTOBLLO_{mp} = \sum_{(j, k), h} (RTOBLLO_{mp, (j, k), h})$

$UDAOPT_{mp} = \sum_{(j, k), h} (DAOPT_{mp, (j, k), h})$

$$UDAOBL_{mp} = \sum_{(j,k),h} (DAOBL_{mp,(j,k),h})$$

$$UOPTS_{mp} = \sum_{(j,k),h} (OPTS_{mp,(j,k),h})$$

$$UOBLS_{mp} = \sum_{(j,k),h} (OBLS_{mp,(j,k),h})$$

$$UOPTP_{mp} = \sum_{(j,k),h} (OPTP_{mp,j,h})$$

$$UOBLP_{mp} = \sum_{(j,k),h} (OBLP_{mp,(j,k),h})$$

[NPRR1201: Delete the formulas "$UOPTS_{mp}$", "$UOBLS_{mp}$", "$UOPTP_{mp}$", and "$UOBLP_{mp}$" above upon system implementation.]

$$UWSLTOT_{mp} = (-1) * \sum_{r,b} (MEBL_{mp,r,b})$$

[NPRR1012: Insert the formula "$UDAASOAWD_{mp}$" below upon system implementation of the Real-Time Co-Optimization (RTC) project:]

$$UDAASOAWD_{mp} = \sum_{h} (DARUOAWD_{mp,h} + DARDOAWD_{mp,h} + DARROAWD_{mp,h} + DANSOAWD_{mp,h} + DAECROAWD_{mp,h})$$

$$USOGTOT_{mp} = \sum_{gsc} (MEBSOGNET_{mp,gsc}) + \sum_{p,i} (RTMGSOGZ_{mp,p,i})$$

[NPRR995: Insert the formula "$USOCLTOT_{mp}$" below upon system implementation:]

$$USOCLTOT_{mp} = (-1) * \sum_{gsc,b} (WSOL_{mp,gsc,b})$$

The above variables are defined as follows:

Variable	Unit	Definition
$DURSCP_{cp}$	$	*Default Uplift Ratio Share per Counter-Party*—The Counter-Party's pro rata portion of the total short-pay amount for all Day-Ahead Market (DAM) and Real-Time Market (RTM) Invoices for a month.
TSPA	$	*Total Short Pay Amount*—The total short-pay amount calculated by ERCOT to be collected through the Default Uplift Invoice process.
$MMARS_{cp}$	None	*Maximum MWh Activity Ratio Share*—The Counter-Party's pro rata share of Maximum MWh Activity in the reference month.
MMA_{cp}	MWh	*Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction in the reference month.
MMATOT	MWh	*Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity in the reference month.

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Variable	Unit	Definition
RTMG $_{mp, p, r, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTMG $_{mp}$	MWh	*Uplift Real-Time Metered Generation per Market Participant*—The monthly sum of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTDCIMP $_{mp, p, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTDCIMP $_{mp}$	MW	*Uplift Real-Time DC Import per Market Participant*—The monthly sum of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.
RTAML $_{mp, p, i}$	MWh	*Real-Time Adjusted Metered Load per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML) at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTAML $_{mp}$	MWh	*Uplift Real-Time Adjusted Metered Load per Market Participant*—The monthly sum of the AML represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQES $_{mp, p, i}$	MW	*QSE-to-QSE Energy Sale per Market Participant per Settlement Point*—The amount of MW sold by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTQQES $_{mp}$	MWh	*Uplift QSE-to-QSE Energy Sale per Market Participant*—The monthly sum of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
URTQQEP $_{mp}$	MWh	*Uplift QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAES $_{mp, p, h}$	MW	*Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE.
UDAES $_{mp}$	MWh	*Uplift Day-Ahead Energy Sale per Market Participant*—The monthly total of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAEP $_{mp, p, h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s ~~cleared~~ DAM Energy Bids and Energy Bid Curves, cleared in the DAM, at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.

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Variable	Unit	Definition
UDAEP $_{mp}$	MWh	*Uplift Day-Ahead Energy Purchase per Market Participant*—The monthly total of energy represented by Market Participant *mp*'s ~~cleared~~ DAM Energy Bids and Energy Bid Curves, cleared in the DAM, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBL $_{mp, (j, k), h}$	MW	*Real-Time Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s Point-to-Point (PTP) Obligations with the source *j* and the sink *k* settled in Real-Time for the hour *h*, and where the Market Participant is a QSE.
URTOBL $_{mp}$	MWh	*Uplift Real-Time Obligation per Market Participant*—The monthly total of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBLLO $_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
URTOBLLO $_{q, (j, k)}$	MW	*Uplift Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAOPT $_{mp, (j, k), h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
UDAOPT $_{mp}$	MWh	*Uplift Day-Ahead Option per Market Participant*—The monthly total of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
DAOBL $_{mp, (j, k), h}$	MW	*Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
UDAOBL $_{mp}$	MWh	*Uplift Day-Ahead Obligation per Market Participant*—The monthly total of Market Participant *mp*'s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTS $_{mp, (j, k), a, h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOPTS $_{mp}$	MWh	*Uplift PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp, (j, k), a, h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.

Variable	Unit	Definition
UOBLS $_{mp}$	MWh	*Uplift PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp, (j, k), a, h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOPTP $_{mp}$	MWh	*Uplift PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLP $_{mp, (j, k), a, h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
UOBLP $_{mp}$	MWh	*Uplift PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
[NPRR1201: Delete the variables "OPTS $_{mp, (j, k), a, h}$", "UOPTS $_{mp}$", "OBLS $_{mp, (j, k), a, h}$", "UOBLS $_{mp}$", "OPTP $_{mp, (j, k), a, h}$", "UOPTP $_{mp}$", "OBLP $_{mp, (j, k), a, h}$", "UOBLP $_{mp}$" above upon system implementation.]		
UWSLTOT $_{mp}$	MWh	*Uplift Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.
MEBL $_{mp, r, b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*.

Variable	Unit	Definition
[NPRR1012: Insert the variables below upon system implementation of the Real-Time Co-Optimization (RTC) project:]		
UDAASOAWD $_{mp}$	MWh	*Uplift Day-Ahead Ancillary Service Only Award per Market Participant*—The monthly total of Market Participant *mp's* Ancillary Service Only Offers awarded in DAM, where the Market Participant is a QSE assigned to the registered Counter-Party.
DARUOAWD $_{mp, h}$	MW	*Day-Ahead Reg-Up Only Award per Market Participant*—The Reg-Up Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DARDOAWD $_{mp, h}$	MW	*Day-Ahead Reg-Down Only Award per Market Participant*—The Reg-Down Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DARROAWD $_{mp, h}$	MW	*Day-Ahead Responsive Reserve Only Award per Market Participant*—The Responsive Reserve (RRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DANSOAWD $_{mp, h}$	MW	*Day-Ahead Non-Spin Only Award per Market Participant*—The Non-Spin Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
DAECROAWD $_{mp, h}$	MW	*Day-Ahead ERCOT Contingency Reserve Service Only Award per Market Participant*—The ERCOT Contingency Reserve Service (ECRS) Only capacity quantity awarded in the DAM to the Market Participant *mp* for the hour *h*.
USOGTOT $_{mp}$	MWh	*Uplift Real-Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by Settlement Only Generators (SOGs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party. ***[NPRR995: Replace the definition above with the following upon system implementation:]*** *Uplift Real-Time Settlement Only Generator Site per Market Participant*—The monthly sum of Real-Time energy produced by Settlement Only Generators (SOGs), Settlement Only Distribution Generators (SODGs), Settlement Only Transmission Generators (SOTGs), Settlement Only Distribution Energy Storage Systems (SODESSs), or Settlement Only Transmission Energy Storage Systems (SOTESSs) represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.
[NPRRR995: Insert the variable "USOCLTOT $_{mp}$" below upon system implementation:]		
USOCLTOT $_{mp}$	MWh	*Uplift Real-Time Settlement Only Charging Load per Market Participant*—The monthly sum of Real-Time charging Load that is WSL by SODESSs and SOTESSs represented by Market Participant *mp*, where the Market Participant is a QSE assigned to the registered Counter-Party.

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Variable	Unit	Definition
RTMGSOGZ $_{mp, p, i}$	MWh	*Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), Settlement Only Distribution Generators (SODGs), and Settlement Only Transmission Generators (SOTGs) at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that opted out of nodal pricing pursuant to Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG) or a Settlement Only Transmission Generator (SOTG), will also be included in this value. ***[NPRR995: Replace the definition above with the following upon system implementation:]*** *Real-Time Metered Generation from Settlement Only Generators Zonal per QSE per Settlement Point*—The total Real-Time energy produced by Settlement Only Transmission Self-Generators (SOTSGs) for the Market Participant *mp* in Load Zone Settlement Point *p*, for the 15-minute Settlement Interval. MWh quantities for Energy Storage System (ESS), SODGs, and SOTGs at sites where the ESS capacity constitutes more than 50% of the total SOG nameplate capacity will be included in this value. MWh quantities for SODGs and SOTGs that opted out of nodal pricing pursuant to Section 6.6.3.8, Real-Time Payment or Charge for Energy from a Settlement Only Distribution Generator (SODG), Settlement Only Transmission Generator (SOTG), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS), will also be included in this value.
MEBSOGNET $_{q, gsc}$	MWh	*Net Metered energy at gsc for an SODG or SOTG Site*—The net sum for all Settlement Meters for SODG or SOTG site *gsc* represented by QSE *q*. A positive value indicates an injection of power to the ERCOT System. ***[NPRR995: Replace the definition above with the following upon system implementation:]*** *Net Metered energy at gsc for an SODG, SOTG, SODESS, or SOTESS Site*—The net sum for all Settlement Meters for SODG, SOTG, SODESS, or SOTESS site *gsc* represented by QSE *q* for the 15-minute Settlement Interval. A positive value indicates an injection of power to the ERCOT System.
[NPRRR995: Insert the variable "WSOL $_{mp, gsc, b}$" below upon system implementation:]		
WSOL $_{mp, gsc, b}$	MWh	*WSL for an SODESS or SOTESS Site*—The WSL as measured for an for SODESS or SOTESS site *gsc* at Electrical Bus *b*, represented by the Market Participant *mp*, represented as a negative value, for the 15-minute Settlement Interval.
cp	none	A registered Counter-Party.
mp	none	A Market Participant with MWh activity in the reference month that is a currently-registered QSE or CRR Account Holder or that voluntarily terminated its QSE or CRR Account Holder registration.
j	none	A source Settlement Point.

Variable	Unit	Definition
k	none	A sink Settlement Point.
a	none	A CRR Auction.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval i.
r	none	A Resource.
gsc	none	A generation site code.
b	none	An Electrical Bus.

(3) The uplifted short-paid amount will be allocated to the Market Participants (QSEs or CRR Account Holders) assigned to a registered Counter-Party based on the pro-rata share of MWhs that the QSE or CRR Account Holder contributed to its Counter-Party's maximum MWh activity ratio share.

(4) Any uplifted short-paid amount greater than $2,500,000 must be scheduled so that no amount greater than $2,500,000 is charged on each set of Default Uplift Invoices until ERCOT uplifts the total short-paid amount. ERCOT must issue Default Uplift Invoices at least 30 days apart from each other.

(5) ERCOT shall issue Default Uplift Invoices no earlier than 90 days following a short-pay of a Settlement Invoice on the date specified in the Settlement Calendar. The Invoice Recipient is responsible for accessing the Invoice on the MIS Certified Area once posted by ERCOT.

(6) Each Default Uplift Invoice must contain:

(a) The Invoice Recipient's name;

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

(c) Net Amount Due or Payable – the aggregate summary of all charges owed by a Default Uplift Invoice Recipient;

(d) Run Date – the date on which ERCOT created and published the Default Uplift Invoice;

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

(f) Default Uplift Invoice Reference – an identification code used to reference the amount uplifted;

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

(h) Remittance Information Details – details including the account number, bank name, and electronic transfer instructions of the ERCOT account to which any amounts owed by the Invoice Recipient are to be paid or of the Invoice Recipient's account from which ERCOT may draw payments due; and

(i) Overdue Terms – the terms that would apply if the Market Participant makes a late payment.

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

10.2.2 TSP and DSP Metered Entities

Commented [CP17]: Please note NPRR1246 also proposes revisions to this section.

(1) Each Transmission Service Provider (TSP) and Distribution Service Provider (DSP) is responsible for supplying ERCOT with meter data associated with:

(a) All Loads using the ERCOT System;

(b) Any Settlement Only Distribution Generator (SODG); a DSP may make some or all such meters ERCOT-Polled Settlement (EPS) compliant and may request that ERCOT poll the meters. Notwithstanding the foregoing sentence, meter data is not required from:

(i) Generation owned by a Non-Opt-In Entity (NOIE) and used for the NOIE's self-use (not serving Customer Load);

(ii) Distributed Renewable Generation (DRG) with a design capacity less than 50 kW interconnected to a DSP where the owner chooses not to have the out-flow measured in accordance with P.U.C. SUBST. R. 25.213, Metering for Distributed Renewable Generation; and

(iii) Distributed Generation (DG) interconnected to a DSP behind a registered NOIE boundary metering point, not registered as a Generation Resource and with an installed capacity below the DG registration threshold, as determined in Section 16.5, Registration of a Resource Entity, and posted on the ERCOT website.

(c) NOIE or External Load Serving Entity (ELSE) points of delivery where metering points are radial Loads and are uni-directionally metered and NOIE points of delivery that have bi-directional flows that are solely the result of generation interconnected to a Transmission and/or Distribution Service Provider (TDSP) owned Distribution System behind a NOIE point of delivery metering point. A TSP or DSP has the option of making some or all such meters EPS compliant and to request that ERCOT poll the meters; ~~and~~

(d) Generation participating in a current Emergency Response Service (ERS) Contract Period, where such generation only exports energy to the ERCOT System during an ERS deployment or ERS test;~~.~~ and

(e) Load that has TDSP read meter(s) and is participating as a Controllable Load Resource (CLR) that is not an Aggregate Load Resource (ALR). The CLR must be metered separately from all other Loads and generation.

(2) Each TSP and DSP is responsible for the following:

(a) Compliance with the procedures and standards in this Section, the Settlement Metering Operating Guide (SMOG) and the Operating Guides;

(b) Installation, control, and maintenance of the Settlement Metering Facilities, as more fully described in this Section and the SMOG, which includes meters, recorders, instrument transformers, wiring, and miscellaneous equipment required to measure electrical energy;

(c) Costs incurred in the installation and maintenance of these Metering Facilities and communications except for incremental costs incurred for functions not required for the Settlement of the Load or Generation Resource, Settlement Only Generator (SOG), or Load Resource. These incremental costs shall be borne by the Entities requesting the service pursuant to the TSP or DSP tariffs; and

(d) Installation, maintenance, data collection, and related communications, telemetry for the Metering Facilities, and related services necessary to meet the mandatory Interval Data Recorder (IDR) requirements detailed in this Section, Section 18, Load Profiling, and the SMOG.

10.2.3 ERCOT-Polled Settlement Meters

(1) ERCOT shall poll Metering Facilities that meet any one of the following criteria:

(a) Generation connected directly to the ERCOT Transmission Grid, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT Transmission Grid during equipment testing, an ERS deployment, or an ERS test;

(b) Auxiliary meters used for generation netting by ERCOT;

(c) Generation delivering 10 MW or more to the ERCOT System, unless the generation is participating in a current ERS Contract Period and the generation only exports energy to the ERCOT System during equipment testing, an ERS deployment, or an ERS test;

(d) Generation participating in any Ancillary Service market;

(e) NOIE points connected bi-directionally to the ERCOT System, unless the bi-directional energy flows are the sole result of generation interconnected to a TDSP owned Distribution System behind a NOIE point of delivery metering point;

(f) Direct Current Ties (DC Ties);

(g) DG where there is an energy storage Load Resource that has associated Wholesale Storage Load (WSL);

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

(g) Metering required to determine the Wholesale Storage Load (WSL) or Non-WSL Settlement Only Charging Load associated to a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS);

(h) Metering required to determine WSL associated with an Energy Storage Resource (ESR); ~~and~~

(i) Metering required to determine the Non-WSL ESR Charging Load; ~~and~~

(j) Metering required to measure the consumption of a Load that has registered as a CLR with ERCOT and is not an ALR, where the CLR is behind the Point of Interconnection (POI) of a generator, as reflected in an ERCOT-approved EPS Design Proposal. The CLR must be metered separately from all other Loads and generation through a single EPS metering point.

(2) Additionally, ERCOT shall poll any SODG or NOIE metering point at the request of such Entity, provided the Metering Facility meets all requirements and approvals associated with EPS metering requirements of this Section and the SMOG. Load Resources that have registered as a CLR with ERCOT and are not an ALR, where the CLR is ~~of~~ 10 MW or more and the CLR is the only Load behind the Service Delivery Point such that it can be separately metered at its Service Delivery Point ~~on the ERCOT System~~, may, at their option have an EPS Meter.

10.3.2.3 Generation Netting for ERCOT-Polled Settlement Meters

Commented [CP18]: Please note NPRR1246 also proposes revisions to this section.

(1) Each Generation Resource and Settlement Only Generator (SOG) and each Load that is designated to be netted with that Generation Resource or SOG, including construction and maintenance Load that is netted with existing generation auxiliaries, must be physically metered at its POI to the ERCOT Transmission Grid or Service Delivery Point, or, in accordance with Section 10.3.2.2, Loss Compensation of EPS Meter Data, loss-compensated to its POI to the ERCOT Transmission Grid. Interval Data Recorders (IDRs) must be used to determine generator output or Load usage. In the intervals where the generation output exceeds the Load, the net must be settled as generation. In the

intervals where the Load exceeds the generation output, the net must be settled as Load, and carry any applicable Load shared charges and credits.

(2) For Settlement purposes, netting is not allowed except under the configurations described in paragraphs (2)(a) through (2)(e) below, and only if the service arrangement is otherwise lawful. ERCOT has no obligation to independently determine whether a site configuration that includes both Loads and Generation Resource(s) or SOGs complies with Public Utility Regulatory Act (PURA) or the Public Utility Commission of Texas (PUCT) Substantive Rules, and ERCOT's approval of a metering proposal for such a site is not a verification of the legality of that arrangement:

(a) Single POI or Service Delivery Point;

(b) Transmission-level interconnections where all POIs are located at the same substation, at the same voltage, and under normal operating conditions, are interconnected through common electrical equipment such as circuit breakers, connecting cables, bus bars, switches/isolators. Qualifying station arrangements include, but are not limited to, Generation and Load connected in a line bus, ring bus, double-breaker, or breaker-and-a-half configuration;

(c) Multiple POIs where the Loads and generator output are electrically connected to a common switchyard, as defined in paragraph (8~~7~~) below. In addition, there must be sufficient generator capacity to serve all plant Loads for netting to occur;

(d) A Qualifying Facility (QF) with POIs, where the QF is selling energy to a thermal host, may net the Load meters of the thermal host with the QF's generation meters when the Load and generation are electrically connected to a common switchyard. In instances in which Load is served by new on-site generation through a common switchyard, the TSP or DSP may install monitoring equipment necessary for measuring Load to determine stranded cost charges, if any are applicable, as determined under the PURA and applicable PUCT rules. For purposes of this Section, new on-site generation has the meaning as contained in Public Utility Regulatory Act, TEX. UTIL. CODE ANN. §§ 39.252 and 39.262(k) (Vernon 1998 & Supp. 2007) (PURA); or

(e) For Generation Resources and/or Load with flow-through on a private, contiguous transmission system (not included in a TSP or DSP rate base) and in a configuration existing as of October 1, 2000, the meters at the interconnections with the ERCOT Transmission Grid may be netted for the purpose of determining Generation Resources or Load. For Settlement purposes, when the net is a Load, the metered interconnection points must be assigned to the same Load Zone and Unaccounted for Energy (UFE) zone.

(3) For Energy Storage Resource (ESR) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.