(a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:

(i) The total energy into the ESR must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and

(ii) The auxiliary Load energy shall be stored in the EPS Meter's IDR, per channel assignments defined in the SMOG.

(b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and

(c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (8~~7~~) below.

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

(3) For Energy Storage Resource (ESR), Settlement Only Distribution Energy Storage System (SODESS), or Settlement Only Transmission Energy Storage System (SOTESS) sites, Wholesale Storage Load (WSL) must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities.

(a) For configurations where the Resource Entity telemeters an auxiliary Load value to the EPS Meter:

(i) The total energy into the ESR, SODESS, or SOTESS must be separately metered from all other Loads and generation, and must be metered using EPS Metering Facilities; and

(ii) The auxiliary Load energy shall be stored in the EPS Meter's IDR, per channel assignments defined in the SMOG.

(b) For configurations where the WSL is not at a POI, it must be metered behind a single POI metering point, per the requirements in paragraph (3) or (3)(a) above; and

(c) WSL for a compressed air energy storage Load Resource is exempt from the requirement to be electrically connected to a common switchyard, as defined in paragraph (8~~7~~) below.

(4) For a generation site with a single POI and one or more Controllable Load Resources (CLRs) behind the POI~~, as indicated in an approved EPS Design Proposal, a TDSP shall install~~ an EPS Meter to separately measure each CLR Load is required. ~~if t~~The TDSP(s) must install the EPS Meter only if~~and~~ all of the Entities consuming energy behind the

POI, including the Resource Entity for such generation site~~, agree with~~ consent in writing to the metering arrangement, and the arrangement is included in an EPS Design Proposal that is approved by ERCOT~~, but only if the Resource Entity for such generation site has provided the TDSP written consent to provide service to the Customer or Wholesale Customer associated with the CLR. A TDSP's submission of an updated EPS Design Proposal reflecting the addition of EPS Metering to measure CLR Load shall constitute confirmation to ERCOT that the Resource Entity has provided such written consent~~. The CLR shall provide notice to all Entities consuming energy behind the POI of its request for installation of an EPS Meter.

(5~~4~~) ERCOT shall maintain descriptions of the Metering Facilities of all common switchyards that contain multiple POIs of Loads (ESI IDs) and generation meters (EPS). The description is limited to identifying the Entities within a common switchyard and a simplified diagram showing the metering configuration of all Supervisory Control and Data Acquisition (SCADA) and Settlement Metering points.

(6~~5~~) All Load(s) included in the netting arrangement for an EPS Metering Facility shall only be electrically connected to the ERCOT Transmission Grid through the EPS metering point(s) for such Facility. Such Loads shall not be electrically connected to the ERCOT Transmission Grid through electrical connections that are not metered by the EPS metering point(s) for the Facility.

(7~~6~~) Notwithstanding the requirements of paragraph (6~~5~~) above, auxiliary Load(s) connected to the station service transformer not to exceed 500 kW in aggregate shall be permitted an additional electrical connection to a TSP's or DSP's Facilities through a separately metered Transmission and/or Distribution Service Provider (TDSP) read metering point. In locations subject to multiple certificated service areas, the Resource Entity shall notify each DSP that has the right to serve in the service area of the proposed connection. This configuration requires mutual agreement between the connecting TSP, DSP, and Resource Entity, and the connection shall be achieved through an open transition load transfer switch listed for emergency service and shall only be used in emergency and maintenance situations.

(8~~7~~) For purposes of this Section, a common switchyard is defined as an electric substation Facility where the POI for Load and Generation Resources are located at the same Facility but where the interconnection points are physically not greater than 400 yards apart. The physical connections of the Load to its POI and the Generation Resource to its POI cannot be Facilities that have been placed in a TSP's or DSP's rate base.

(9~~8~~) Notwithstanding any other provision in this Section, for any Generation Resource or ESR that is configured to serve a Customer Load as part of a Private Microgrid Island (PMI), the connection to the Customer Load in the PMI configuration shall be located behind the EPS metering point at the Resource's POI. For a PMI configuration that includes an ESR that is receiving WSL treatment for charging Load, an EPS Meter shall be located to measure the ESR's gross output net of any internal telemetered auxiliary Load, and a separate TDSP ESI ID (for nodal Settlement) with a Load Serving Entity (LSE) association must be established for the site prior to service of any Load.

[NPRR945: Insert paragraph (10~~9~~) below upon system implementation and renumber accordingly:]

(10~~9~~) ERCOT shall post on the ERCOT website a report listing all Generation Resources or Settlement Only Generators (SOGs) that have achieved commercial operations, excluding Decommissioned Generation Resources, Mothballed Generation Resources, and decommissioned SOGs, whose Resource Registration data indicates that the Generation Resource or SOG is part of a Private Use Network. The report must identify the name of the Generation Resource or SOG site, its nameplate capacity, and the date the Generation Resource or SOG was added to the report. The report shall not identify any confidential, customer-specific information regarding netted loads. ERCOT shall update the list at least monthly.

(11~~9~~) Notwithstanding any other provision in this Section, for any Generation Resource or ESR that elects for Load(s) located behind the EPS metering point at the Resource's POI to be excluded from the netting arrangement for an EPS Metering Facility, a Load EPS meter shall be located behind the EPS metering point at the Resource's POI and a separate TDSP ESI ID with an LSE association must be established for the site prior to Load(s) being removed from the netting arrangement. This configuration requires mutual agreement between the connecting TSP, DSP, Resource Entities, and any other Load(s) behind the EPS metering point. The above requirement to have a separate TDSP ESI ID with an LSE association does not apply to EPS Metering Facilities that are located behind a Non-Opt-In Entity (NOIE) meter point.

11.1.6 ERCOT-Polled Settlement Meter Netting

(1) As allowed by Section 10, Metering, of these Protocols, ERCOT will perform the approved netting schemes, which sum the meters at a given Generation Resource site.

[NPRR1002: Replace paragraph (1) above with the following upon system implementation:]

(1) As allowed by Section 10, Metering, of these Protocols, ERCOT will perform the approved netting schemes, which sum the meters at a given Generation Resource~~,~~ or Energy Storage Resource (ESR) site.

(2) Both Load consumption and Generation Resource production meters will be combined together to obtain a total amount of Load or Resource.

[NPRR1002: Replace paragraph (2) above with the following upon system implementation:]

(2) Both Load consumption and generation production meters will be combined together to obtain a total amount of Load or generation.

(3) For a Generation Resource site with Wholesale Storage Load (WSL):

[NPRR995 and NPRR1002: Replace applicable portions of paragraph (3) above with the following upon system implementation:]

(3) For an ESR site:

(a) WSL is measured by the corresponding EPS Meter, except that when a Resource Entity for an Energy Storage Resource (ESR) communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS Meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be zero.

(b) For WSL that is metered behind the POI metering point, the WSL will be added back into the POI metering point to determine the net flows for the POI metering point.

(c) For WSL that is separately metered at the POI, the WSL will not be included in the determination of whether the generation site is net generation or net Load for the purpose of Settlement.

(4) For a~~n~~ single POI Generation Resource site that includes an ESR whose charging Load is not~~that has separately metered its charging Load, but elects not to~~ receiving~~e~~ WSL treatment or includes a Controllable Load Resource (CLR):~~, the Non-WSL ESR Charging Load for the 15-minute interval shall be determined using the metered ESR charging Load.~~

(a) The portion of Non-WSL ESR Charging Load or CLR Load supplied from the grid will be adjusted for Distribution Losses, ~~and~~ Transmission Losses, and UFE;

(b) The portion of Non-WSL ESR Charging Load or CLR Load supplied from the co-located generation will not be adjusted for Distribution Losses, ~~and~~ Transmission Losses, and UFE;

(c) For RTAML, 4-CP, and Load Ratio Share (LRS) volumes, only the Non-WSL ESR Charging Load or CLR Load supplied from the grid (after loss and UFE adjustment) shall be included~~The total Non-WSL ESR Charging Load or CLR Load will be adjusted for UFE~~; and

(d) For Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node, (the Non-WSL ESR Charging Load or CLR Load shall be the Load supplied from the grid (after loss and UFE adjustment) plus the Non-WSL ESR Charging Load or CLR Load supplied from the co-located generation~~For sites with multiple ESRs and/or CLRs, an ESI ID is required for each ESR and CLR and the unadjusted energy supplied from the grid will be allocated to each ESI ID based upon Load Ratio Share (LRS) using metered Non-WSL ESR Charging Load or CLR Load or calculated Non-WSL ESR Charging Load;~~.

(e) An ESI ID is required for each ESR and CLR and the unadjusted energy supplied from the grid will be allocated to each ESI ID.

(f) For sites with multiple ESRs or CLRs, the unadjusted energy supplied from the grid will be allocated to each ESI ID based upon load ratio share using metered Non-WSL ESR Charging Load or CLR Load or calculated Non-WSL ESR Charging Load.

(g~~5~~) For a single POI Generation Resource site that includes an ESR that has separately metered its charging Load ~~but elects not to receive WSL treatment~~, the Non-WSL ESR Charging Load for the 15-minute interval shall be determined using the metered ESR Charging Load.

(5~~6~~~~5~~) For an ESR that has not separately metered its charging Load, or has forfeited WSL treatment pursuant to paragraph (3) of Section 10.2.4, Resource Entity Calculation and Telemetry of ESR Auxiliary Load Values, the Non-WSL ESR Charging Load for the 15-minute interval shall be equal to the total metered ESR Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(a) The lesser of the total metered ESR Load or X MWh, where X is calculated as 15% of the ESR's nameplate capacity multiplied by 0.25; or

(b) 15% of the total metered ESR Load for the 15-minute interval.

(6~~7~~) For a single POI Generation Resource site that includes a CLR, CLR Load shall be metered with an EPS Meter and the metered energy will be considered as Generation Resource production to determine the net flows for Settlement of the corresponding generation site.

[NPRR995: Insert paragraphs (7~~8~~~~6~~) and (8~~9~~~~7~~) below upon system implementation and renumber accordingly:]

(7~~8~~~~6~~) For a Settlement Only Distribution Energy Storage System (SODESS) or Settlement Only Transmission Energy Storage System (SOTESS) that has been approved for WSL treatment and has a single POI or Service Delivery Point:

(a) For withdrawals from the ERCOT System consisting of only WSL or WSL in combination with auxiliary Load:

(i) WSL is measured by the corresponding EPS Meter, except when a Resource Entity communicates its auxiliary Load value to the EPS Meter, WSL is calculated by subtracting the auxiliary Load from the total Load measured by the corresponding EPS Meter. If the calculated auxiliary Load is greater than the total Load, WSL shall be set to zero.

(ii) For measured or calculated WSL that is behind the POI or Service Delivery Point, the WSL will be added back into the POI or Service Delivery Point metering point to determine the net flows for the POI or Service Delivery Point metering point.

(b) For withdrawals from the ERCOT System that include Load other than WSL Load or auxiliary Load:

(i) The charging Load is measured by the corresponding EPS Meter, except that when the Resource Entity communicates its auxiliary Load value to the EPS Meter, the charging Load is calculated by subtracting the auxiliary Load from the total SODESS or SOTESS Load measured by the corresponding EPS Meter. If the calculated auxiliary Load is greater than the total SODESS or SOTESS Load, the charging Load shall be set to zero.

(ii) Where injections are exclusively the result of generation from an SODESS or SOTESS, the WSL quantity shall be determined through the use of a generation accumulator, which is calculated as the accumulated output measured at the POI or Service Delivery Point minus the accumulated charging Load receiving WSL treatment. The charging Load that is less than or equal to the generation accumulator will be settled as WSL for each 15-minute interval.

(iii) Where injections are the result of a combination of SODESS or SOTESS and non-SODESS or non-SOTESS generation, the output channel of the EPS Meter that measures charging Load is required to be used for Settlement. For these sites, the WSL quantity shall be determined through the use of a generation accumulator, which is calculated as the lesser of (i) the accumulated SODESS or SOTESS output or (ii) the accumulated output measured at the POI or Service Delivery Point minus the accumulated charging Load receiving WSL treatment. The charging Load that is less than or equal to the generation accumulator will be settled as WSL for each 15-minute interval.

(iv) For measured or calculated charging Load that is behind the POI or Service Delivery Point, the charging Load will be added back into the POI or Service Delivery Point metering point to determine the net flows for the POI or Service Delivery Point metering point.

(8~~97~~) For an SODESS or SOTESS that either has not elected or has not been approved for WSL treatment and has a single POI or Service Delivery Point:

(a) For withdrawals from the ERCOT System consisting of only charging Load or charging Load in combination with auxiliary Load, the Non-WSL Settlement Only Charging Load for the 15-minute Settlement Interval shall be determined as follows:

(i) The metered charging Load that would otherwise be eligible for WSL; or

(ii) The total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(A) The lesser of the total metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the ESS multiplied by 0.25; or

(B) 15% of the total SODESS or SOTESS metered Load.

(b) For withdrawals from the ERCOT System that include Load other than Non-WSL Settlement Only Charging Load or auxiliary Load, the Non-WSL Settlement Only Charging Load for the 15-minute Settlement Interval shall be determined as follows:

(i) Where injections are exclusively the result of generation from an SODESS or SOTESS, the Non-WSL Settlement Only Charging Load quantity shall be determined through the use of a generation accumulator, which is calculated as the accumulated output measured at the POI or Service Delivery Point minus the metered or calculated charging Load determined in option (A) or (B) below:

(A) Where the charging Load is separately metered, the accumulated metered charging Load that would otherwise be eligible for WSL; or

(B) Where the charging Load is not separately metered, the accumulated total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(1) The lesser of the total SODESS or SOTESS metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the SODESS or SOTESS multiplied by 0.25; or

(2) 15% of the total SODESS or SOTESS metered Load.

(ii) Where injections are the result of a combination of generation from SODESS or SOTESS and other generating facilities, the output channel of the EPS meter that measures charging Load is required to be used for Settlement. For these sites, the Non-WSL Settlement Only Charging Load quantity shall be determined through the use of a generation accumulator, which is calculated as the lesser of (a) the accumulated SODESS or SOTESS output or (b) the accumulated output measured at the POI or Service Delivery Point minus:

(A) Where the charging Load is separately metered, the accumulated metered charging Load that would otherwise be eligible for WSL; or

(B) Where the charging Load is not separately metered, the accumulated total metered SODESS or SOTESS Load minus auxiliary Load, where auxiliary Load is calculated as the greater of the following:

(1) The lesser of the total metered Load or X MWh, where X is calculated as 15% of the nameplate capacity of the SODESS or SOTESS multiplied by 0.25; or

(2) 15% of the total SODESS or SOTESS metered Load.

(iii) For each 15-minute interval, the metered or calculated charging Load that is less than or equal to the generation accumulator will be settled as Non-WSL Settlement Only Charging Load.

(7~~6~~) For a Generation Resource or ESR that excludes its Load(s) from the netting arrangement pursuant to paragraph (9) of Section 10.3.2.3, Generation Netting for ERCOT-Polled Settlement Meters:

(a) Non-charging Load(s) are measured by the corresponding EPS Meter, except that when a Resource Entity for an ESR communicates its non-charging Load(s) value(s) to the EPS Meter using approved calculation methods.

(b) For non-charging Load(s) that are metered behind the POI metering point, the Load will be added back into the POI metering point to determine the net flows for the POI metering point.

(c) For non-charging Load(s) that are separately metered at the POI, the non-charging Load will not be included in the determination of whether the generation site is net generation or net Load for the purpose of Settlement.

16.11.4.1 Determination of Total Potential Exposure for a Counter-Party

(1) A Counter-Party's TPE is the sum of its "Total Potential Exposure Any" (TPEA) and TPES:

(a) TPEA is the positive net exposure of the Counter-Party not included in TPES.

(b) TPES is the positive net exposure of the Counter-Party for Future Credit Exposure (FCE) and the Independent Amount (IA).

(2) For all Counter-Parties:

$$\text{TPEA} = \text{Max}\,[0, \text{MCE}, \text{Max}\,[0, ((1\text{-TOA}) * \text{EAL}_q + \text{TOA} * \text{EAL}_t + \text{EAL}_a)]] + \text{PUL}$$

$$\text{TPES} = \text{Max}\,[0, \text{FCE}_a] + \text{IA}$$

The above variables are defined as follows:

Variable	Unit	Description
EAL_q	$	*Estimated Aggregate Liability for all QSEs that represents Load or generation*—EAL for all QSEs represented by the Counter-Party if at least one QSE represented by the Counter-Party represents either Load or generation.
EAL_t	$	*Estimated Aggregate Liability for all QSEs* —EAL for all QSEs represented by the Counter-Party if none of the QSEs represented by the Counter-Party represent either Load or generation.
EAL_a	$	*Estimated Aggregate Liability for all CRR Account Holders*—EAL for all CRR Account Holders represented by the Counter-Party.
PUL	$	*Potential Uplift*—Potential uplift to the Counter-Party, to the extent and in the proportion that the Counter-Party represents Entities to which an uplift of a short payment will be made pursuant to Section 9.19, Partial Payments by Invoice Recipients. It is calculated as the sum of: (a) Amounts expected to be uplifted within one year of the date of the calculation; and (b) the lesser of: (i) 25% of amounts expected to be uplifted beyond one year of the date of the calculation; or (ii) five years' worth of uplift charges.
FCE_a	$	*Future Credit Exposure for all CRR Account Holders*—FCE for all CRR Account Holders represented by the Counter-Party.
MCE	$	*Minimum Current Exposure*—For each Counter-Party, ERCOT shall determine a Minimum Current Exposure (MCE) as follows: $MCE = Max[RFAF * MAF * Max[\{\sum_e \sum_{i=1}^{96} \sum_p [L_{i, od, p} * RTSPP_{i, od, p}]/n\}, \{\sum_e \sum_{i=1}^{96} \sum_p [[[L_{i, od, p} * T2 - G_{i, od, p} * (1-NUCADJ) * T3] * RTSPP_{i, od, p}] + [RTQQNET_{i, od, p} * T5]]/n\},$ $\{\sum_e \sum_{i=1}^{96} \sum_p [G_{i, od, p} * NUCADJ * T1 * RTSPP_{i, od, p}]/n\},$ $\{\sum_e \sum_{i=1}^{96} \sum_p DARTNET_{i, od, p} * T4/n\}],$ $MAF * IMCE]$ $RTQQNET_{i, od, p} = Max[\sum_c (RTQQES_{i, od, p, c} - RTQQEP_{i, od, p, c}), BTCF * \sum_c (RTQQES_{i, od, p, c} - RTQQEP_{i, od, p, c})] * RTSPP_{i, od, p}$ $DARTNET_{i, od, p} = DAM\ EOO\ Cleared_{i, od, p} * DART_{i, od, p} + DAM\ TPO\ Cleared_{i, od, p} * DART_{i, od, p} + DAM\ PTP\ Cleared_{i, od, p} * DARTPTP_{i, od, p} - DAM\ EOB\ Cleared_{i, od, p} * DART_{i, od, p}$ Where: $G_{i, od, p}$ = *Total <u>Net</u> Metered Generation at all Resource Nodes<u>, including Wholesale Storage Load and Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs)</u>* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p* $L_{i, od, p}$ = *Total Adjusted Metered Load (AML) at all Load Zones<u>, excluding CLR Load of CLRs that are not ALRs</u>* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*

Variable	Unit	Description
		MAF = *Market Adjustment Factor*—Used to provide for the potential for overall price increases based on changes to ERCOT market rules or market conditions. This factor shall not be set below 100%. Revisions to this factor will be recommended by the Technical Advisory Committee (TAC) and the ERCOT Finance and Audit (F&A) Committee, and approved by the ERCOT Board. Such revisions shall be implemented on the 45th calendar day following ERCOT Board approval unless otherwise directed by the ERCOT Board.
		NUCADJ = *Net Unit Contingent Adjustment*—To allow for situations where a generator may unintentionally or intentionally meet its requirement from the Real-Time Market (RTM)
		$\text{RTQQNET}_{i, od, p}$ = *Net QSE-to-QSE Energy Trades* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{RTQQES}_{i, od, p, c}$ = *QSE Energy Trades* for which the Counter-Party is the seller for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*
		$\text{RTQQEP}_{i, od, p, c}$ = *QSE Energy Trades* for which the Counter-Party is the buyer for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*
		BTCF = *Bilateral Trades Credit Factor*
		$\text{RTSPP}_{i, od, p}$ = *Real-Time Settlement Point Price* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DARTNET}_{i, od, p}$ = *Net DAM ~~a~~<u>A</u>ctivities* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DART}_{i, od, p}$ = *Day-Ahead - Real-Time Spread* for interval *i* for Operating Day *od* at Settlement Point *p*
		DAM EOB Cleared $_{i, od, p}$ = *DAM Energy Only Bids <u>and Energy Bid Curves</u> Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		DAM EOO Cleared $_{i, od, p}$ = *DAM Energy Only Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		DAM TPO Cleared $_{i, od, p}$ = *DAM Three-Part Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		DAM PTP Cleared $_{i, od, p}$ = *DAM Point-to-Point (PTP) Obligations Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DARTPTP}_{i, od, p}$ = *Day-Ahead - Real-Time Spread* for value of PTP Obligation for interval *i* for Operating Day *od* at Settlement Point *p*
		c = Bilateral Counter-Party
		cif = *Cap Interval Factor* - Represents the historic largest percentage of System-Wide Offer Cap (SWCAP) intervals during a calendar day
		e = Most recent *n* Operating Days for which RTM Initial Settlement Statements are available
		i = Settlement Interval
		n = Days used for averaging
		nm = Notional Multiplier

Variable	Unit	Description
		od = Operating Day *p* = A Settlement Point

[NPRR1013: Replace the variable "MCE" above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project:]

MCE	$	*Minimum Current Exposure*—For each Counter-Party, ERCOT shall determine a Minimum Current Exposure (MCE) as follows: $\text{MCE} = \text{Max}[\text{RFAF} * \text{MAF} * \text{Max}[\{\sum_{e}\sum_{i=1}^{96}\sum_{p}[\text{L}_{i, od, p} * \text{RTSPP}_{i, od, p}]/n\}, \{\sum_{e}\sum_{i=1}^{96}\sum_{p}[[[\text{L}_{i, od, p} * T2 - \text{G}_{i, od, p} * (1-NUCADJ) * T3] * \text{RTSPP}_{i, od, p}] + [\text{RTQQNET}_{i, od, p} * T5]]/n\}, \{\sum_{e}\sum_{i=1}^{96}\sum_{p}[\text{G}_{i, od, p} * NUCADJ * T1 * \text{RTSPP}_{i, od, p}]/\text{n}\}, \{\{\sum_{e}\sum_{i=1}^{96}\sum_{p}\text{DARTNET}_{i, od, p} * T4/n\} + \{\sum_{e}\sum_{i=1}^{96}\text{DARTASONET}_{i, od, c} * T4/n\}\}], \text{MAF} * \text{IMCE}]$ $\text{RTQQNET}_{i, od, p} = \text{Max}[\sum_{c}(\text{RTQQES}_{i, od, p, c} - \text{RTQQEP}_{i, od, p, c}), BTCF * \sum_{c}(\text{RTQQES}_{i, od, p, c} - \text{RTQQEP}_{i, od, p, c})] * \text{RTSPP}_{i, od, p}$ $\text{DARTNET}_{i, od, p} = \text{DAM EOO Cleared}_{i, od, p} * \text{DART}_{i, od, p} + \text{DAM TPO Cleared}_{i, od, p} * \text{DART}_{i, od, p} + \text{DAM PTP Cleared}_{i, od, p} * \text{DARTPTP}_{i, od, p} - \text{DAM EOB Cleared}_{i, od, p} * \text{DART}_{i, od, p}$ $\text{DARTASONET}_{i, od} = \text{DAM ASOO Cleared}_{i, od} * \text{DARTMCPC}_{i, od}$ Where: $\text{G}_{i, od, p}$ = *Total Net Metered Generation at all Resource Nodes, including Wholesale Storage Load and Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs)* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p* $\text{L}_{i, od, p}$ = *Total Adjusted Metered Load (AML) at all Load Zones, excluding CLR Load of CLRs that are not ALRs* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p* MAF = *Market Adjustment Factor*—Used to provide for the potential for overall price increases based on changes to ERCOT market rules or market conditions. This factor shall not be set below 100%. Revisions to this factor will be recommended by the Technical Advisory Committee (TAC) and the ERCOT Finance and Audit (F&A) Committee, and approved by the ERCOT Board. Such revisions shall be implemented on the 45th

Variable	Unit	Description
		calendar day following ERCOT Board approval unless otherwise directed by the ERCOT Board.
		NUCADJ = *Net Unit Contingent Adjustment*—To allow for situations where a generator may unintentionally or intentionally meet its requirement from the Real-Time Market (RTM)
		$\text{RTQQNET}_{i,\ od,\ p}$ = *Net QSE-to-QSE Energy Trades* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{RTQQES}_{i,\ od,\ p,\ c}$ = *QSE Energy Trades* for which the Counter-Party is the seller for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*
		$\text{RTQQEP}_{i,\ od,\ p,\ c}$ = *QSE Energy Trades* for which the Counter-Party is the buyer for interval *i* for Operating Day *od* at Settlement Point *p* with Counter-Party *c*
		$\text{DARTASONET}_{i,\ od}$ = *Net DAM Ancillary Service Only ~~a~~Activities* for interval *i* for Operating Day *od*
		$\text{DAM ASOO Cleared}_{i,\ od}$ = *DAM Ancillary Service Only Offers Cleared in DAM* for interval *i* for Operating Day *od*
		$\text{DARTMCPC}_{i,\ od}$ = Day-Ahead – Real-Time MCPC Spread for interval *i* for Operating Day *od*
		BTCF = *Bilateral Trades Credit Factor*
		$\text{RTSPP}_{i,\ od,\ p}$ = *Real-Time Settlement Point Price* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DARTNET}_{i,\ od,\ p}$ = *Net DAM ~~a~~Activities* for the Counter-Party for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DART}_{i,\ od,\ p}$ = *Day-Ahead - Real-Time Spread* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DAM EOB Cleared}_{i,\ od,\ p}$ = *DAM Energy Only Bids and Energy Bid Curves Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DAM EOO Cleared}_{i,\ od,\ p}$ = *DAM Energy Only Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DAM TPO Cleared}_{i,\ od,\ p}$ = *DAM Three-Part Offers Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DAM PTP Cleared}_{i,\ od,\ p}$ = *DAM Point-to-Point (PTP) Obligations Cleared* for interval *i* for Operating Day *od* at Settlement Point *p*
		$\text{DARTPTP}_{i,\ od,\ p}$ = *Day-Ahead - Real-Time Spread* for value of PTP Obligation for interval *i* for Operating Day *od* at Settlement Point *p*
		c = Bilateral Counter-Party
		cif = *Cap Interval Factor* - Represents the historic largest percentage of System-Wide Offer Cap (SWCAP) intervals during a calendar day
		e = Most recent *n* Operating Days for which RTM Initial Settlement Statements are available
		i = Settlement Interval
		n = Days used for averaging

Variable	Unit	Description
		nm = Notional Multiplier *od* = Operating Day *p* = A Settlement Point
IMCE	$	*Initial Minimum Current Exposure* IMCE = TOA * (SWCAP * *nm* * *cif%*)
TOA	None	*Trade-Only Activity*—Counter-Party that does not represent either a Load or a generation QSE. Set to "0" if Counter-Party represents a QSE that has an association with a Load Serving Entity (LSE) or a Resource Entity, or if Counter-Party does not represent any QSE; otherwise set to 1.
q	None	QSEs represented by Counter-Party.
a	None	CRR Account Holders represented by Counter-Party.
IA	$	*Independent Amount*—The amount required to be posted as defined in Section 16.16.1, Counter-Party Criteria.
RFAF	None	*Real-Time Forward Adjustment Factor*—The adjustment factor for RTM-related forward exposure as defined in Section 16.11.4.3.3, Forward Adjustment Factors.

The above parameters are defined as follows:

Parameter	Unit	Current Value*
nm	None	50
cif	Percentage	9%
NUCADJ	Percentage	Minimum value of 20%.
T1	Days	2
T2	Days	5
T3	Days	5
T4	Days	1
T5	Days	For a Counter-Party that represents Load this value is equal to 5, otherwise this value is equal to 2.
BTCF	Percentage	80%
n	Days	14
* The current value for the parameters referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(3) If ERCOT, in its sole discretion, determines that the TPEA or the TPES for a Counter-Party calculated under paragraphs (1) or (2) above does not adequately match the financial risk created by that Counter-Party's activities under these Protocols, then ERCOT may set a different TPEA or TPES for that Counter-Party. ERCOT shall, to the extent practical, give to the Counter-Party the information used to determine that different TPEA or TPES. ERCOT shall provide written or electronic Notice to the Counter-Party of the basis for ERCOT's assessment of the Counter-Party's financial risk and the resulting creditworthiness requirements.

(4) ERCOT shall monitor and calculate each Counter-Party's TPEA and TPES daily.

16.11.4.3.2 Real-Time Liability Estimate

(1) ERCOT shall estimate RTL for an Operating Day as the sum of estimates for the following RTM Settlement charges and payments:

(a) Section 6.6.3.1, Real-Time Energy Imbalance Payment or Charge at a Resource Node, using Real-Time Net Metered Generation (RTMG) including Controllable Load Resources (CLRs) that are not Aggregate Load Resources (ALRs) as generation estimate;

(b) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone, using 14-day or seven-day-old LRS for Load estimate;

[NPRR829: Replace item (b) above with the following upon system implementation:]

(b) Section 6.6.3.2, Real-Time Energy Imbalance Payment or Charge at a Load Zone, using 14-day or seven-day-old LRS for Load estimate and Real-Time telemetry of net generation as the generation estimate;

(c) Section 6.6.3.3, Real-Time Energy Imbalance Payment or Charge at a Hub;

(d) Section 6.6.3.4, Real-Time Energy Payment for DC Tie Import;

(e) 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), using the Real-Time telemetry, if provided, of net generation as the outflow estimate and the Real-Time Price for each SODG or SOTG site;

[NPRR995 and NPRR1077: Replace applicable portions of item (e) above with the following upon system implementation:]

(e) 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), using the Real-Time telemetry of net generation as the outflow estimate and the Real-Time Price for each SODG, SOTG, SODESS, or SOTESS site;

(f) Section 6.6.4, Real-Time Congestion Payment or Charge for Self-Schedules; and

[NPRR1013: Insert items (g)-(k) below upon system implementation of the Real-Time Co-Optimization (RTC) project and renumber accordingly:]

(g) Section 6.7.5.1, Regulation Up Payments and Charges;

(h) Section 6.7.5.2, Regulation Down Payments and Charges;

(i) Section 6.7.5.3, Responsive Reserve Payments and Charges;

(j) Section 6.7.5.4, Non-Spinning Reserve Payments and Charges; and

(k) Section 6.7.5.5, ERCOT Contingency Reserve Service Payments and Charges.

(g) Section 7.9.2.1, Payments and Charges for PTP Obligations Settled in Real-Time.

26.2 Securitization Default Charges

Commented [CP19]: Please note NPRR1246 also proposes revisions to this section.

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

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

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

Where:

$$SDCMMARS_{cp} = SDCMMA_{cp} / SDCMMATOT$$

$$SDCMMA_{cp} = \text{Max}\ \{ \textstyle\sum_{mp} (SDCRTMG_{mp} + SDCRTDCIMP_{mp}),$$

$$\textstyle\sum_{mp} (SDCRTAML_{mp} + SDCWSLTOT_{mp}),$$

$$\textstyle\sum_{mp} SDCRTQQES_{mp},$$

$$\textstyle\sum_{mp} SDCRTQQEP_{mp},$$

$\sum_{mp}$ SDCDAES $_{mp}$,

$\sum_{mp}$ SDCDAEP $_{mp}$,

$\sum_{mp}$ (SDCRTOBL $_{mp}$ + SDCRTOBLLO $_{mp}$),

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

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

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

Where:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The above variables are defined as follows:

Variable	Unit	Definition
SDCRSCP $_{cp}$	$	*Securitization Default Charge Ratio Share per Counter-Party*—The Counter-Party's pro rata portion of the total Securitization Charges for a month.
TSDCMA	$	*Total Securitization Default Charge Monthly Amount*—The amount ERCOT determines must be collected for the month in order to timely repay the Securitization Default Balance.
SDCMMARS $_{cp}$	None	*Securitization Default Charge Maximum MWh Activity Ratio Share*—The Counter-Party's pro rata share of Maximum MWh Activity.
SDCMMA $_{cp}$	MWh	*Securitization Default Charge Maximum MWh Activity*—The maximum MWh activity of all Market Participants represented by the Counter-Party in the DAM, RTM and CRR Auction for the reference month.
SDCMMATOT	MWh	*Securitization Default Charge Maximum MWh Activity Total*—The sum of all Counter-Party's Maximum MWh Activity.
RTMG $_{mp, p, r, i}$	MWh	*Real-Time Metered Generation per Market Participant per Settlement Point per Resource*—The Real-Time energy produced by the Generation Resource *r* represented by Market Participant *mp*, at Resource Node *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTMG $_{mp}$	MWh	*Securitization Default Charge Real-Time Metered Generation per Market Participant*—The monthly sum in the reference month of Real-Time energy produced by Generation Resources represented by Market Participant *mp*, excluding generation for RMR Resources and generation in RUC-Committed Intervals, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTDCIMP $_{mp, p, i}$	MW	*Real-Time DC Import per QSE per Settlement Point*—The aggregated Direct Current Tie (DC Tie) Schedule submitted by Market Participant *mp,* as an importer into the ERCOT System through DC Tie *p*, for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTDCIMP $_{mp}$	MW	*Securitization Default Charge Real-Time DC Import per Market Participant*—The monthly sum in the reference month of the aggregated DC Tie Schedule submitted by Market Participant *mp*, as an importer into the ERCOT System where the Market Participant is a QSE assigned to a registered Counter-Party.
RTAMLEXSECM $_{mp, p, i}$	MWh	*Real-Time Adjusted Metered Load Excluding Load Exempt from Sub M per Market Participant per Settlement Point*—The sum of the Adjusted Metered Load (AML), excluding Load that is exempt from Securitization Default Charges pursuant to the Declaratory Order entered by the Public Utility Commission of Texas (PUCT) in PUCT Docket No. 56122, Petition of Electric Reliability Council of Texas, Inc. for Expedited Declaratory Order Regarding Public Utility Regulatory Act Chapter 39, Subchapter M, at the Electrical Buses that are included in Settlement Point *p* represented by Market Participant *mp* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTAML $_{mp}$	MWh	*Securitization Default Charge Real-Time Adjusted Metered Load per Market Participant*—The monthly sum in the reference month of the AML, excluding Load exempt from Securitization Default Charges pursuant to the Declaratory Order entered by the PUCT in PUCT Docket No. 56122, 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.

Variable	Unit	Definition
SDCRTQQES $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Sale per Market Participant*—The monthly sum in the reference month of MW sold by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
RTQQEP $_{mp, p, i}$	MW	*QSE-to-QSE Energy Purchase per Market Participant per Settlement Point*—The amount of MW bought by Market Participant *mp* through Energy Trades at Settlement Point *p* for the 15-minute Settlement Interval *i*, where the Market Participant is a QSE.
SDCRTQQEP $_{mp}$	MWh	*Securitization Default Charge QSE-to-QSE Energy Purchase per Market Participant*—The monthly sum in the reference month of MW bought by Market Participant *mp* through Energy Trades, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAES $_{mp, p, h}$	MW	*Day-Ahead Energy Sale per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offers at Settlement Point *p*, for the hour *h*, where the Market Participant is a QSE.
SDCDAES $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Sale per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s cleared Three-Part Supply Offers in the DAM and cleared DAM Energy-Only Offer Curves, where the Market Participant is a QSE assigned to the registered Counter-Party.
DAEP $_{mp, p, h}$	MW	*Day-Ahead Energy Purchase per Market Participant per Settlement Point per hour*—The total amount of energy represented by Market Participant *mp*'s ~~cleared~~ DAM Energy Bids and Energy Bid Curves, cleared in the DAM, at Settlement Point *p* for the hour *h*, where the Market Participant is a QSE.
SDCDAEP $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Energy Purchase per Market Participant*—The monthly total in the reference month of energy represented by Market Participant *mp*'s ~~cleared~~ DAM Energy Bids 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.
SDCRTOBL $_{mp}$	MWh	*Securitization Default Charge Real-Time Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations settled in Real-Time, counting the quantity only once per source and sink pair, and where the Market Participant is a QSE assigned to the registered Counter-Party.
RTOBLLO $_{q, (j, k)}$	MW	*Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The total MW of the QSE's PTP Obligation with Links to an Option Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour.
SDCRTOBLLO $_{q, (j, k)}$	MW	*Securitization Default Charge Real-Time Obligation with Links to an Option per QSE per pair of source and sink*—The monthly total in the reference month of Market Participant *mp*'s MW of PTP Obligation with Links to Options Bids cleared in the DAM and settled in Real-Time for the source *j* and the sink *k* for the hour, where the Market Participant is a QSE assigned to the registered Counter-Party.

Variable	Unit	Definition
OPT $_{mp, (j, k), h}$	MW	*Day-Ahead Option per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Options with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
SDCDAOPT $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Option per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Options owned in the DAM, counting the ownership quantity only once per source and sink pair, and where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
DAOBL $_{mp, (j, k), h}$	MW	*Day-Ahead Obligation per Market Participant per source and sink pair per hour*—The number of Market Participant *mp*'s PTP Obligations with the source *j* and the sink *k* owned in the DAM for the hour *h*, and where the Market Participant is a CRR Account Holder.
SDCDAOBL $_{mp}$	MWh	*Securitization Default Charge Day-Ahead Obligation per Market Participant*—The monthly total in the reference month of Market Participant *mp*'s PTP Obligations owned in the DAM, counting the ownership quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTS $_{mp, (j, k), a, h}$	MW	*PTP Option Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTS $_{mp}$	MWh	*Securitization Default Charge PTP Option Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option offers awarded in CRR Auctions, counting the awarded quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLS $_{mp, (j, k), a, h}$	MW	*PTP Obligation Sale per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation offers with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOBLS $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Sale per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation offers awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OPTP $_{mp, (j, k), a, h}$	MW	*PTP Option Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Option bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.
SDCOPTP $_{mp}$	MWh	*Securitization Default Charge PTP Option Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Option bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
OBLP $_{mp, (j, k), a, h}$	MW	*PTP Obligation Purchase per Market Participant per source and sink pair per CRR Auction per hour*—The MW quantity that represents the total of Market Participant *mp*'s PTP Obligation bids with the source *j* and the sink *k* awarded in CRR Auction *a*, for the hour *h*, where the Market Participant is a CRR Account Holder.

Variable	Unit	Definition
SDCOBLP $_{mp}$	MWh	*Securitization Default Charge PTP Obligation Purchase per Market Participant*—The MW quantity that represents the monthly total in the reference month of Market Participant *mp*'s PTP Obligation bids awarded in CRR Auctions, counting the quantity only once per source and sink pair, where the Market Participant is a CRR Account Holder assigned to the registered Counter-Party.
SDCWSLTOT $_{mp}$	MWh	*Securitization Default Charge Metered Energy for Wholesale Storage Load at bus per Market Participant*—The monthly sum in the reference month of Market Participant *mp*'s Wholesale Storage Load (WSL) energy metered by the Settlement Meter which measures WSL.
MEBL $_{mp,\ r,\ b}$	MWh	*Metered Energy for Wholesale Storage Load at bus*—The WSL energy metered by the Settlement Meter which measures WSL for the 15-minute Settlement Interval represented as a negative value, for the Market Participant *mp*, Resource *r*, at bus *b*.
cp	none	A registered Counter-Party.
mp	none	A Market Participant that is a QSE or CRR Account Holder with activity in the reference month, except for a Market Participant exempt from Securitization Default Charges pursuant to the Final Order entered by the PUCT in PUCT Docket No. 52321, Application of Electric Reliability Council of Texas, Inc. for a Debt Obligation Order Pursuant to Chapter 39, Subchapter M. Defaulted Market Participants with market activity in the reference month are included in the calculation.
j	none	A source Settlement Point.
k	none	A sink Settlement Point.
a	none	A CRR Auction.
p	none	A Settlement Point.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
r	none	A Resource.

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

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

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

ERCOT Impact Analysis Report

NPRR Number	1188	NPRR Title	Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources
Impact Analysis Date	June 27, 2023		
Estimated Cost/Budgetary Impact	Between \$1.8M and \$2.5M		
Estimated Time Requirements	The timeline for implementing this Nodal Protocol Revision Request (NPRR) is dependent upon Public Utility Commission of Texas (PUCT) prioritization and approval. Estimated project duration: 18 to 24 months		
ERCOT Staffing Impacts (across all areas)	Implementation Labor: 57% ERCOT; 43% Vendor Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	The following ERCOT systems would be impacted: • Market Operation Systems 63% • Settlements & Billing Systems 22% • Credit 6% • Energy Management Systems 2% • Data Management & Analytic Systems 2% • Credit Management Systems (CMM) 1% • Resource Integration and Ongoing Operations (RIOO) 1% • Integration Systems 1% • Channel Management Systems 1% • ERCOT Website and MIS Systems 1% • EPS Metering 1%		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1215	NPRR Title	Clarifications to the Day-Ahead Market (DAM) Energy-Only Offer Calculation
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	4.4.10, Credit Requirement for DAM Bids and Offers		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) clarifies that the Day-Ahead Market (DAM) Energy-Only Offer credit exposure calculation zeros out negative values, with any zeroed out values being included in the calculation of the dp^{th} percentile difference. This clarification aligns with how ERCOT has been performing the calculation since Nodal Go-Live. It also clarifies that the "absolute value" of negative prices is used to increase exposure when prices are negative. Finally, it incorporates a default e2 value in the Protocols, which is consistent with "Procedures for Setting Nodal Day Ahead Market (DAM) Credit Requirement Parameters," which was an Other Binding Document (OBD) approved by the ERCOT Board of Directors in July of 2012. Although NPRR671, Incorporation of DAM Credit Parameters into Protocols, approved in April of 2015, attempted to incorporate that OBD into Protocols, it appears to have inadvertently not incorporated the default e2 value into the Protocols at that time. Finally, this NPRR clarifies the definitions of e-factors.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience		

Board Report

	☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR clarifies the calculation of the credit exposure of the DAM Energy-Only Offer. The current language could be read to imply that negative values are excluded from the calculation, but this is not the case. Negative values are set to zero and then included in the calculation. It also clarifies that the "absolute value" of negative prices is used to increase exposure when prices are negative. As currently written, the Protocol language could inaccurately be read to mean that negative prices could decrease exposure, when the opposite is true. This NPRR also incorporates the default e2 value of zero into the Protocols. As currently written, it is not clear that the formula in paragraph (6)(b)(i)(A) of Section 4.4.10 is only applied when favorable treatment is requested by a Market Participant, and that absent that request, it has been ERCOT's practice since the outset to set e2 to zero. Finally, this NPRR makes clarifications to the definition of e-factors.
PRS Decision	On 2/8/24, PRS voted unanimously to table NPRR1215 and refer the issue to the Credit Finance Sub Group (CFSG). All Market Segments participated in the vote. On 5/9/24, PRS voted unanimously to recommend approval of NPRR1215 as amended by the 4/12/24 ERCOT comments. All Market Segments participated in the vote. On 6/13/24, PRS voted unanimously to endorse and forward to TAC the 5/9/24 PRS Report and 1/23/24 Impact Analysis for NPRR1215. All Market Segments participated in the vote.

Board Report

Summary of PRS Discussion	On 2/8/24, the sponsor provided an overview of NPRR1215. On 5/9/24, participants noted the CFSG endorsement of the 4/12/24 ERCOT comments. On 6/13/24, there was no discussion.
TAC Decision	On 6/24/24, TAC voted unanimously to recommend approval of NPRR1215 as recommended by PRS in the 6/13/24 PRS Report. All Market Segments participated in the vote. On 8/28/24, TAC voted unanimously to table NPRR1215. All Market Segments participated in the vote. On 9/19/24, TAC voted unanimously to recommend approval of NPRR1215 as recommended by TAC in the 6/24/24 TAC Report as amended by the 8/1/24 ERCOT comments as revised by TAC. All Market Segments participated in the vote.
Summary of TAC Discussion	On 6/24/24, there was no additional discussion beyond TAC review of the items below. On 8/28/24, ERCOT Staff reviewed the 8/1/24 ERCOT comments and requested tabling of NPRR1215 for additional time to review questions raised by stakeholders which might require additional revisions to NPRR1215. On 9/19/24, participants reviewed the 8/1/24 ERCOT comments and a desktop edit to clarify verbiage within paragraph (6)(e) of Section 4.4.10.
TAC Review/Justification of Recommendation	☒ Revision Request ties to Reason for Revision as explained in Justification ☒ Impact Analysis reviewed and impacts are justified as explained in Justification ☒ Opinions were reviewed and discussed ☒ Comments were reviewed and discussed (if applicable) ☐ Other: (explain)
ERCOT Board Decision	On 8/20/24, the ERCOT Board voted unanimously to remand NPRR1215 to TAC. On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NPRR1215 as recommended by TAC in the 9/19/24 TAC Report.

Board Report

Opinions	
Credit Review	ERCOT Credit Staff and CFSG have reviewed NPRR1215 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1215.
ERCOT Opinion	ERCOT supports approval of NPRR1215.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1215 and believes the market impact for NPRR1215 is to clarify how ERCOT calculates credit exposure for bids and offers in the DAM.

Sponsor	
Name	Curry Holden / Katherine Gross
E-mail Address	Curry.Holden@ercot.com / Katherine.Gross@ercot.com
Company	ERCOT
Phone Number	512-248-6520 / 512-225-7184
Cell Number	
Market Segment	Not applicable

Market Rules Staff Contact	
Name	Cory Phillips
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Comments Received	
Comment Author	**Comment Summary**
CFSG 02234	Requested PRS continue to table NPRR1215 for further review
ERCOT 041224	Proposed additional clarifying edits based on CFSG discussions
CFSG 041824	Endorsed NPRR1215 as amended by the 4/12/24 ERCOT comments
ERCOT 080124	Proposed corrections to the 6/24/24 TAC Report and requested the ERCOT Board remand NPRR1215 to TAC for additional review

Board Report

Market Rules Notes

Please note that the following NPRR(s) also propose revisions to Section 4.4.10:

- NPRR1188, Implement Nodal Dispatch and Energy Settlement for Controllable Load Resources

Proposed Protocol Language Revision

4.4.10 Credit Requirement for DAM Bids and Offers

Commented [CP1]: Please note NPRR1188 also proposes revisions to this section.

(1) Each QSE's ability to bid and offer in the DAM is subject to credit exposure from the QSE's bids and offers being within the credit limit for DAM participation established for the entire Counter-Party of which the QSE is part, as specified in item (1) of Section 16.11.4.6.2, Credit Requirements for DAM Participation, and taking into account the credit exposure of accepted DAM bid and offers of the Counter-Party's other QSEs.

(2) DAM bids and offers of all QSEs of the Counter-Party are accepted in the order submitted while ensuring that the credit exposure from accepted bids and offers do not exceed the Counter-Party's credit limit for DAM participation.

(3) ERCOT shall reject the QSE's individual bids and offers whose credit exposure, as calculated in item (6) below, exceeds the Counter-Party's credit limit for DAM participation as described in items (1) and (2) above, and shall notify the QSE through the MIS Certified Area as soon as practicable.

(4) The QSE may revise and resubmit such rejected bids and offers described in item (3) above, provided that the resubmitted bids and offers are valid and within the Counter-Party's credit limit for DAM participation adjusted for all accepted DAM bids and offers of the Counter-Party's QSE's limit and that such resubmission occurs prior to 1000 of the Operating Day.

(5) The DAM shall use the Counter-Party's credit limit for DAM participation provided and adjusted for accepted bids and offers for DAM transactions cleared, until a new credit limit for DAM participation is available.

(6) ERCOT shall calculate credit exposure for bids and offers in the DAM as follows:

(a) For a DAM Energy Bid, the credit exposure shall be calculated as the quantity of the bid multiplied by a bid exposure price that is calculated as follows:

(i) If the price of the DAM Energy Bid is less than or equal to zero, the bid exposure price for that quantity will equal zero.

(ii) If the price of the DAM Energy Bid is greater than zero, the bid exposure price for that quantity will equal the greater of zero or the sum of (A) and (B):

(A) The lesser of:

(1) The d^{th} percentile of the Day-Ahead Settlement Point Price (DASPP) for the hour over the previous 30 days; and

(2) The bid price.

(B) The value *e1* multiplied by (bid price minus (A)) when the bid price is greater than (A).

(1) The value *e1* is computed as the *ep1*th percentile of Ratio1 for the 30 days prior to the Operating Day, where Ratio1 is calculated daily as follows:

~~Ratio1 = Min[1, Max[0, ($\sum_{h=1,24}$ ($Q_{cleared\ Bids}$*P_{DAM} – $Q_{cleared\ Offers}$*P_{DAM}))/ ($\sum_{h=1,24}$ $Q_{cleared\ Bids}$*P_{DAM})]]~~

~~except Ratio1 = 1 when $\sum_{h=1,24}$ $Q_{cleared\ Bids}$*P_{DAM} = 0~~

Ratio1 = Min[1, Max[0, ($\sum_{h=1,24} \sum_p$ (DAM EOB Cleared $_{h,p}$ * DASPP $_{h,p}$ - DAM EOO Cleared $_{h,p}$ * DASPP $_{h,p}$ - DAM TPO Cleared $_{h,p}$ * DASPP $_{h,p}$))/ ($\sum_{h=1,24} \sum_p$ (DAM EOB Cleared $_{h,p}$ * DASPP $_{h,p}$))]]

except Ratio1 = 1 when $\sum_{h=1,24} \sum_p$ (DAM EOB Cleared $_{h,p}$ * DASPP $_{h,p}$) = 0

The above variables are defined as follows:

Variable	Unit	Definition
DAM EOB Cleared $_{h,p}$	MWh	*DAM Energy Only Bids Cleared.* DAM Energy Only Bids Cleared for Operating Hour *h* at Settlement Point *p*
DAM EOO Cleared $_{h,p}$	MWh	*DAM Energy Only Offers Cleared.* DAM Energy Only Offers Cleared for Operating Hour *h* at Settlement Point *p*
DAM TPO Cleared $_{h,p}$	MWh	*DAM Three-Part Offers Cleared.* DAM Three-Part Offers Cleared for Operating Hour *h* at Settlement Point *p*
DASPP $_{h,p}$	$/MWh	Day-Ahead Settlement Point Price for Operating Hour *h* at Settlement Point *p*
h	none	An Operating Hour.
p	none	A Settlement Point.

(2) Default values are outlined in paragraph (10) below.

(3) A Counter-Party may request for favorable treatment as described in paragraph (7) below and, upon ERCOT agreeing to such request, ERCOT may adjust *e1* by changing the quantity of bids or offers to the values

reported by the Counter-Party in paragraph (7~~8~~) below or based on information available to ERCOT.

(iii) For DAM Energy Bids of curve quantity type, the credit exposure shall be the credit exposure, as calculated above, at the price and MW quantity of the bid curve that produces the maximum credit exposure for the DAM Energy Bid.

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

(a) For a DAM Energy Bid or for each MW portion of the bid portion of an Energy Bid/Offer Curve, the credit exposure shall be calculated as the quantity of the bid multiplied by a bid exposure price that is calculated as follows:

(i) If the price of the DAM Energy Bid or the price on the bid portion of an Energy Bid/Offer Curve is less than or equal to zero, the bid exposure price for that quantity will equal zero.

(ii) If the price of the DAM Energy Bid or the price on the bid portion of an Energy Bid/Offer Curve is greater than zero, the bid exposure price for that quantity will equal the greater of zero or the sum of (A) and (B):

(A) The lesser of:

(1) The d^{th} percentile of the Day-Ahead Settlement Point Price (DASPP) for the hour over the previous 30 days; and

(2) The bid price.

(B) The value *e1* multiplied by (bid price minus (A)) when the bid price is greater than (A).

(1) The value *e1* is computed as the *ep1*th percentile of Ratio1 for the 30 days prior to the Operating Day, where Ratio1 is calculated daily as follows:

~~Ratio1 = Min[1, Max[0, ($\sum_{h=1,24}$ ($Q_{cleared\ Bids}$*P_{DAM} – $Q_{cleared\ Offers}$*P_{DAM}))/ ($\sum_{h=1,24}$ $Q_{cleared\ Bids}$*P_{DAM})]]~~

~~except Ratio1 = 1 when $\sum_{h=1,24}$ $Q_{cleared\ Bids}$*P_{DAM} = 0~~

Ratio1 = Min[1, Max[0, ($\sum_{h=1,24} \sum_{p}$ (DAM EOB Cleared $_{h,\,p}$ * DASPP $_{h,\,p}$ - DAM EOO Cleared $_{h,\,p}$ * DASPP $_{h,\,p}$ - DAM TPO Cleared $_{h,\,p}$ * DASPP $_{h,\,p}$))/ ($\sum_{h=1,24} \sum_{p}$ (DAM EOB Cleared $_{h,\,p}$ * DASPP $_{h,\,p}$))]]

except Ratio1 = 1 when $\sum_{h=1,24} \sum_p$ (DAM EOB Cleared $_{h,p}$ * DASPP $_{h,p}$) = 0

The above variables are defined as follows:

Variable	Unit	Definition
DAM EOB Cleared $_{h,p}$	MWh	*DAM Energy Only Bids Cleared.* DAM Energy Only Bids Cleared for Operating Hour *h* at Settlement Point *p*
DAM EOO Cleared $_{h,p}$	MWh	*DAM Energy Only Offers Cleared.* DAM Energy Only Offers Cleared for Operating Hour *h* at Settlement Point *p*
DAM TPO Cleared $_{h,p}$	MWh	*DAM Three-Part Offers Cleared.* DAM Three-Part Offers Cleared for Operating Hour *h* at Settlement Point *p*
DASPP $_{h,p}$	$/MWh	Day-Ahead Settlement Point Price for Operating Hour *h* at Settlement Point *p*
h	none	An Operating Hour.
p	none	A Settlement Point.

(2) Default values are outlined in paragraph (10) below.

(3) A Counter-Party may request for favorable treatment as described in paragraph (7) below and, upon ERCOT agreeing to such request, ERCOT may adjust *e1* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (7~~8~~) below or based on information available to ERCOT.

(iii) For DAM Energy Bids or bid portions of Energy Bid/Offer Curves of curve quantity type, the credit exposure shall be the credit exposure, as calculated above, at the price and MW quantity of the bid curve that produces the maximum credit exposure for the DAM Energy Bid or bid portions of Energy Bid/Offer Curves.

(b) For each MW portion of a DAM Energy-Only Offer:

(i) That has an offer price that is less than or equal to the a^{th} percentile of the DASPP for the hour over the previous 30 days, the sum of (A) and (B) shall apply.

(A) Credit exposure will be:

(1) Reduced (when the b^{th} percentile Settlement Point Price for the hour is positive). The reduction shall be the quantity of the offer multiplied by the b^{th} percentile of the DASPP for the hour over the previous 30 days multiplied by the value *e2*.

(a) The value *e2* is computed as the *ep2*th percentile of Ratio2 for the 30 days prior to the Operating Day, where Ratio2 is calculated daily as follows:

~~Ratio2 = 1 – Max[0, ($\sum_{h=1,24}$ ($Q_{cleared\ Offers}$ – $Q_{cleared\ Bids}$))/($\sum_{h=1,24}$ ($Q_{cleared\ Offers}$))]~~

~~except Ratio2 = 0 when $\sum_{h=1,24}$ $Q_{cleared\ Offers}$ = 0~~

Ratio2 = 1 - Max[0, ($\sum_{h=1,24}$ ((~~(~~DAM EOO Cleared $_{h,p}$ ~~* DASPP $_{h,p}$~~ + DAM TPO Cleared $_{h,p}$ ~~* DASPP $_{h,p}$~~) - DAM EOB Cleared $_{h,p}$ ~~* DASPP $_{h,p}$) DAM EOB Cleared $_{h,p}$ * DASPP $_{h,p}$)~~)/($\sum_{h=1,24}$ (DAM EOO Cleared $_{h,p}$ ~~* DASPP $_{h,p}$~~ + DAM TPO Cleared $_{h,p}$ ~~* DASPP $_{h,p}$~~)))]

except Ratio2 = 0 when $\sum_{h=1,24}$ (DAM EOO Cleared $_{h,p}$ ~~* DASPP $_{h,p}$~~ + DAM TPO Cleared $_{h,p}$ ~~* DASPP $_{h,p}$~~)= 0

Variable	**Unit**	**Definition**
DAM EOB Cleared $_{h,p}$	MWh	*DAM Energy Only Bids Cleared.* DAM Energy Only Bids Cleared for Operating Hour *h* at Settlement Point *p*
DAM EOO Cleared $_{h,p}$	MWh	*DAM Energy Only Offers Cleared.* DAM Energy Only Offers Cleared for Operating Hour *h* at Settlement Point *p*
DAM TPO Cleared $_{h,p}$	MWh	*DAM Three-Part Offers Cleared.* DAM Three-Part Offers Cleared for Operating Hour *h* at Settlement Point *p*
h	none	An Operating Hour.
p	none	A Settlement Point.

(b) Default values are outlined in paragraph (10) below.

(c) A Counter-Party may request for favorable treatment as described in paragraph (7) below and, upon ERCOT agreeing to such request, Ratio2 is calculated at non zero value described above.

(d) ERCOT may adjust the value of *e2* by changing the quantity of bids or offers to the values reported by the Counter-Party in paragraph (7) below or based on information available to ERCOT; or

(2) Increased (when the *b*th percentile Settlement Point Price for the hour is negative). The increase shall be the quantity of the offer multiplied by the absolute value of the *b*th percentile of the DASPP for the hour over the previous 30 days.

(B) Credit exposure will be increased by the product of the quantity of the offer multiplied by the dp^{th} percentile of ~~any positive~~the hourly difference ~~of~~ between Real-Time Settlement Point Price and DASPP (where any negative differences are set to zero) over the previous 30 days for the hour multiplied by *e3*.

(ii) That has an offer price that is greater than the a^{th} percentile of the DASPP for the hour over the previous 30 days, credit exposure will be increased by the product of the quantity of the offer multiplied by the dp^{th} percentile of ~~any positive~~the hourly difference ~~of~~ between Real-Time Settlement Point Price and DASPP (where any negative differences are set to zero) over the previous 30 days for the hour multiplied by *e3*.

(iii) ERCOT may, in its sole discretion, use a percentile other than the dp^{th} percentile of ~~any positive~~the hourly difference ~~of~~ between Real-Time Settlement Point Price and DASPP (where any negative differences are set to zero) over the previous 30 days ~~of the hour~~ in determining credit exposure per this paragraph (6)(b) in evaluating DAM Energy-Only Offers.

(c) For each MW portion of the Energy Offer Curve of a Three-Part Supply Offer:

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

(c) For each MW portion of the Energy Offer Curve of a Three-Part Supply Offer or for each MW portion of the offer portion of an Energy Bid/Offer Curve:

(i) That has an offer price that is less than or equal to the y^{th} percentile of the DASPP for the hour over the previous 30 days, credit exposure will be reduced (when the z^{th} percentile Settlement Point Price is positive) or increased (when the z^{th} percentile Settlement Point Price is negative) by the quantity of the offer multiplied by the absolute value of the z^{th} percentile of the DASPP for the hour over the previous 30 days.

(ii) That has an offer price that is greater than the y^{th} percentile of the DASPP for the hour over the previous 30 days, the credit exposure will be zero.

(iii) For a Combined Cycle Generation Resource with Three-Part Supply Offers for multiple generator configurations, the reduction in credit exposure will be the maximum credit exposure reduction created by the individual Three-Part Supply Offers' Offer Curves (when the z^{th} percentile Settlement Point Price is positive). If the Three-Part Supply Offer causes a credit increase (when the z^{th} percentile Settlement Point Price is negative), the increase in credit exposure will be the maximum credit exposure increase created by the individual Three-Part Supply Offers.

(d) For PTP Obligation Bids:

(i) That have a bid price greater than zero, the sum of the quantity of the bid multiplied by the bid price, plus the u^{th} percentile of the hourly positive price difference between the source Real-Time Settlement Point Price minus the sink Real-Time Settlement Point Price over the previous 30 days multiplied by the quantity of the bid.

(ii) That have a bid price less than or equal to zero, the u^{th} percentile of the hourly positive price difference between the source Real-Time Settlement Point Price minus the sink Real-Time Settlement Point Price over the previous 30 days multiplied by the quantity of the bid.

(iii) Each tenth of a MW quantity (0.1 MW) of an expiring CRR for a Counter-Party can provide credit reduction for only one-tenth of a MW (0.1 MW) of a PTP Obligation bid for that Counter-Party.

(A) The QSE must submit the PTP Obligation bid at the same source and sink pair for the same hour, for the same operating date where the QSE submitting the PTP Obligation bid is represented by the same Counter-Party as the CRR Account Holder that is the owner of record for an expiring CRR, or group of CRRs.

(B) A portion or all of the PTP Obligation bid quantity must be less than or equal to the total of the quantity of all expiring CRRs at the specified source and sink pair and delivery period, less all valid previously submitted PTP Obligation bids at the specified source and sink pair and delivery period.

(iv) For qualified PTP Obligation bids with a bid price greater than zero, ERCOT shall reduce the credit exposure in paragraph (6)(d)(i) above as follows:

Credit Reduction = Reduction Factor * min[PTP bid quantity, remaining expiring CRR MWs] * bid price.

The Reduction Factor is *bd%*. The factor can be adjusted up or down at ERCOT's sole discretion with at least two Bank Business Days' notice. ERCOT may adjust this factor up with less notice, if needed. The expiring CRR may be PTP Options and/or PTP Obligations. If a QSE later cancels the PTP Obligation bid then the amount of exposure credited back to the Counter-Party will be treated as though this PTP Obligation bid was previously offset by expiring CRRs if a matching CRR source and sink pair exists up to the maximum expiring CRR quantity. If a QSE updates the PTP Obligation bid then it will be treated as a cancel followed by a new submission for purposes of credit exposure calculation. Outcome of this calculation is dependent of the sequence of submittals for updates and cancels.

(e) For PTP Obligation bids with Links to an Option with a bid price greater than zero:

Credit ~~Reduction~~Exposure = (1- Reduction Factor *bd*) * (bid quantity * bid price)

(f) For Ancillary Service Obligations not self-arranged, the product of the quantity of Ancillary Service Obligation not self-arranged multiplied by the t^{th} percentile of the hourly MCPC for that Ancillary Service over the previous 30 days for that hour. For negative Self-Arranged Ancillary Service Quantities, the absolute value of the product of the quantity of the negative Self-Arranged Ancillary Service Quantity times the t^{th} percentile of the hourly MCPC for that Ancillary Service over the previous 30 days for that hour.

[NPRR1008 and NPRR1014: Insert applicable portions of paragraph (g) below upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly:]

(g) For Ancillary Service Only Offers, credit exposure will be increased by the sum of the quantity of the Ancillary Service Only Offer multiplied by the dp^{th} percentile of the positive hourly difference for that Ancillary Service between RTMCPC and DAMCPC for that Ancillary Service over the previous 30 days for the Operating Hour of the Ancillary Service Only Offer.

(g) Values *e1*, *e2*, or *e3*, which are applicable to items (a) and (b) above, under conditions described below, will be determined and applied at ERCOT's sole discretion. Within the application parameters identified below, ERCOT shall establish values for *e1*, *e2*, and *e3* and provide notice to an affected Counter-Party of any changes to *e1*, *e2*, or *e3* before 0900 generally two Bank Business Days prior to the normally scheduled DAM 1000 by a minimum of two of these methods: written, electronic, posting to the MIS Certified Area or telephonic. However, ERCOT may adjust any DAM credit parameter immediately if, in its sole discretion, ERCOT determines that the parameter(s) set for a Counter-Party do not adequately match the financial risk created by that Counter-Party's activities in the market. ERCOT shall review the values for *e1*, *e2*, or *e3* for each Counter-Party no less than once every two weeks. ERCOT shall provide written or electronic notice to the Counter-Party of the basis for ERCOT's assessment, or change of assessment, of the exposure adjustment variable established for the Counter-Party and the impact of the adjustment.

(i) The value of each exposure adjustment *e1*, *e2*, and *e3* is a value between zero and one, rounded to the nearest hundredth decimal place, set by ERCOT by Counter-Party. The values ERCOT establishes for *e1*, *e2*, and *e3* for a Counter-Party shall be applied equally to the portfolio of all QSEs represented by such Counter-Party.

(h) ERCOT must re-examine DAM credit parameters immediately if Counter-Party exceeds 90% of its Available Credit Limit (ACL) available to DAM.

(7) A Counter-Party may request more favorable parameters from ERCOT by agreeing to all of the conditions below:

(a) The Counter-Party shall notify ERCOT of any expected changes to Ratio1 or Ratio2, due to change in activity, as described below, and the likely duration of such change as soon as practicable, but no later than two Business Days in advance of the change:

(i) If Ratio1 as defined in paragraph (6)(a)(ii)(B) above is likely to be greater than the Counter-Party's currently assigned value of *e1* for particular day(s), then the estimated daily values of Ratio1 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, and Three-Part Supply Offer quantity assumptions used to arrive at those values; and

(ii) If Ratio2 as defined in paragraph (6)(b)(i)(A)(1) above is likely to be lower than the Counter-Party's currently assigned value of *e2* for particular day(s), then the estimated daily values of Ratio2 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, and Three-Part Supply Offer quantity assumption used to arrive at those values.

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

(a) The Counter-Party shall notify ERCOT of any expected changes to Ratio1 or Ratio2, due to change in activity, as described below, and the likely duration of such change as soon as practicable, but no later than two Business Days in advance of the change:

(i) If Ratio1 as defined in paragraph (6)(a)(ii)(B) above is likely to be greater than the Counter-Party's currently assigned value of *e1* for particular day(s), then the estimated daily values of Ratio1 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, Energy Bid/Offer Curves, and Three-Part Supply Offer quantity assumptions used to arrive at those values; and

(ii) If Ratio2 as defined in paragraph (6)(b)(i)(A)(1) above is likely to be lower than the Counter-Party's currently assigned value of *e2* for particular day(s), then the estimated daily values of Ratio2 specifying the day(s) along with the daily DAM Energy Bid, Energy-Only Offer, Energy Bid/Offer Curves, and Three-Part Supply Offer quantity assumption used to arrive at those values.

(b) ERCOT, in its sole discretion, will determine the adequacy of the disclosures made in item (a) above and may require additional information as needed to evaluate whether a Counter- Party is eligible for favorable treatment.

(c) ERCOT may change the requirements for providing information, as described in item (a) above, to ensure that reasonable information is obtained from Counter-Parties.

(d) ERCOT may, but is not required, to use information provided by a Counter-Party to re-evaluate DAM credit parameters and may take other information into consideration as needed.

(e) If ERCOT determines that information provided to ERCOT is erroneous or that ERCOT has not been notified of required changes, ERCOT may set all parameters for the Counter-Party to the default values with a possible adder on the e1 variable, at ERCOT's sole discretion, for a period of not less than seven days and until ERCOT is satisfied that the Counter-Party has and will comply with the conditions set forth in this Section. In no case shall the adder result in an e1 value greater than one.

(8) Beginning no later than 0800 and ending at 0945 each Business Day, ERCOT shall post to the MIS Certified Area, approximately every 15 minutes, each active Counter-Party's remaining Available Credit Limit (ACL) for that day's DAM and the time at which the report was run.

(9) After the DAM results are posted, ERCOT shall post once each Business Day on the MIS Certified Area each active Counter-Party's calculated aggregate DAM credit exposure and its aggregate DAM credit exposure per transaction type, to the extent available, as it pertains to the most recent DAM Operating Day. The transaction types are:

(a) DAM Energy Bids;

(b) DAM Energy Only Offers;

(c) PTP Obligation Bids;

(d) Three-Part Supply Offers; and

(e) Ancillary Services.

[NPRR1008 and NPRR1014: Replace applicable portions of item (e) above with the following upon system implementation of the Real-Time Co-Optimization (RTC) project for NPRR1008; or upon system implementation for NPRR1014; and renumber accordingly:]

(e) Ancillary Services related to Self-Arranged Ancillary Service Quantities;

(f) Ancillary Service Only Offers;

(g) Energy Bid/Offer Curves.

(10) The parameters in this Section are defined as follows:

(a) The default values of the parameters are:

Parameter	Unit	Current Value*
d	percentile	85
ep1	percentile	95
a	percentile	50
b	percentile	45
dp	percentile	90
ep2	percentile	0
e2	value	0
e3	value	1
y	percentile	45
z	percentile	50
u	percentile	90
bd	%	90
t	percentile	50
* The current value for the parameters referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

(b) The values of the parameters for Entities that meet the requirements in paragraph (7) above for more favorable treatment are:

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Parameter	Unit	Current Value
d	percentile	85
ep1	percentile	75
a	percentile	50
b	percentile	45
dp	percentile	90
ep2	percentile	25
e3	value	1
y	percentile	45
z	percentile	50
u	percentile	90
t	percentile	50
* The current value for the parameters referenced in this table above will be recommended by TAC and approved by the ERCOT Board. ERCOT shall update parameter values on the first day of the month following ERCOT Board approval unless otherwise directed by the ERCOT Board. ERCOT shall provide a Market Notice prior to implementation of a revised parameter value.		

ERCOT Impact Analysis Report

NPRR Number	1215	NPRR Title	Clarifications to the Day-Ahead Market (DAM) Energy-Only Offer Calculation
Impact Analysis Date	January 23, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect following Public Utility Commission of Texas (PUCT) approval.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
None.

Board Report

NPRR Number	1221	NPRR Title	Related to NOGRR262, Provisions for Operator-Controlled Manual Load Shed
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon implementation of Nodal Operating Guide Revision Request (NOGRR) 262, Provisions for Operator-Controlled Manual Load Shed		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	6.5.9.4.2, EEA Levels		
Related Documents Requiring Revision/Related Revision Requests	NOGRR262 Nodal Operating Guide Section 4.5.3.3, EEA Levels (Alignment NOGRR)		
Revision Description	This Nodal Protocol Revision Request (NPRR) aligns provisions regarding manual and automatic firm Load shed; clarifies the proper use and interplay of Under-Voltage Load Shed (UVLS), Under-Frequency Load Shed (UFLS), and manual Load shed; and addresses reliability concerns ERCOT has identified regarding the extent of Transmission Operators' (TOs') manual Load shed capabilities.		
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission		

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	☐ General system and/or process improvement(s) ☒ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR aligns the Nodal Protocols with NOGRR262, which adds language that addresses manual Load shed during an Energy Emergency Alert (EEA). This NPRR maintains existing provisions that allow ERCOT TOs to utilize Loads on UFLS and UVLS circuits to augment manual Load shed capabilities while continuing to comply with UFLS obligations and modifies language to align with North American Electric Reliability Corporation (NERC) Reliability Standards EOP-011-3, Emergency Operations, and EOP-011-4, Emergency Operations. This NPRR also adds provisions that allow a TO to go below its 25% UFLS Load shed obligation when all Load that has been identified as being capable of manual Load shed has been shed. NERC Reliability Standards EOP-011-3 and EOP-011-4 require ERCOT, as a NERC-registered balancing authority, to develop, maintain, and implement operating plan(s) to mitigate capacity emergencies and energy emergencies within its balancing authority area. This NPRR addresses the requirements in EOP-011-3 and EOP-011-4 that the plan(s) must include provisions for TOs to implement operator-controlled manual Load shed during an emergency that accounts for 1) provisions for manual Load shed capable of being implemented in a timeframe adequate for mitigating the emergency; 2) provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that serve designated critical loads; 3) provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS; and 4) provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions.
PRS Decision	On 4/5/24, PRS voted unanimously to table NPRR1221 and refer the issue to ROS. All Market Segments participated in the vote. On 7/18/24, PRS voted unanimously to recommend approval of NPRR1221 as submitted. All Market Segments participated in the vote.

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	On 8/8/24, PRS voted unanimously to endorse and forward to TAC the 7/18/24 PRS Report and 3/20/24 Impact Analysis for NPRR1221. All Market Segments participated in the vote.
Summary of PRS Discussion	On 4/5/24, ERCOT Staff presented NPRR1221; participants requested further review by ROS. On 7/18/24, participants noted the 7/11/24 ROS comments. On 8/8/24, participants reviewed the 3/20/24 Impact Analysis.
TAC Decision	On 8/28/24, TAC voted unanimously to recommend approval of NPRR1221 as recommended by PRS in the 8/8/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/28/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NPRR1221 as recommended by TAC in the 8/28/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1221 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1221.
ERCOT Opinion	ERCOT supports approval of NPRR1221

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ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1221 and believes it provides a positive market impact by ensuring the required alignment between ERCOT and TOs during an EEA Level 3 Load shed event, and ensuring ERCOT and TOs understand their respective responsibilities during an EEA Level 3 firm Load shed event.

Sponsor	
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Market Segment	Not applicable

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Comments Received	
Comment Author	**Comment Summary**
ROS 040424	Requested PRS table NPRR1221 for further review by the Operations Working Group (OWG)
ROS 050224	Requested PRS continue to table NPRR1221 for further review by OWG
ROS 071124	Endorsed NPRR1221 as submitted

Market Rules Notes

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

- NPRR1217, Remove Verbal Dispatch Instruction (VDI) Requirement for Deployment and Recall of Load Resources and Emergency Response Service (ERS) Resources (incorporated 10/1/24)
    - Section 6.5.9.4.2

Proposed Protocol Language Revision

6.5.9.4.2 EEA Levels

(1) ERCOT will declare an EEA Level 1 when PRC falls below 2,500 MW and is not projected to be recovered above 2,500 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 1:

(a) ERCOT shall take the following steps to maintain steady state system frequency near 60 Hz and maintain PRC above 2,000 MW:

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

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

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

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

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

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

(b) QSEs shall:

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

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

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

(ii) Ensure that each of its ESRs suspends charging until the EEA is recalled, except under the following circumstances:

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

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

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

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

(ii) Ensure that each of its ESRs and SOESSs suspends charging until the EEA is recalled, except under the following circumstances:

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

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

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

(2) ERCOT may declare an EEA Level 2 when the clock-minute average system frequency falls below 59.91 Hz for 15 consecutive minutes. ERCOT will declare an EEA Level 2 when PRC falls below 2,000 MW and is not projected to be recovered above 2,000 MW within 30 minutes without the use of the following actions that are prescribed for EEA Level 2:

(a) In addition to the measures associated with EEA Level 1, ERCOT shall take the following steps to maintain steady state system frequency at a minimum of 59.91 Hz and maintain PRC above 1,500 MW:

(i) Instruct TSPs and DSPs or their agents to reduce Customer Load by using existing, in-service distribution voltage reduction measures that have not already been implemented. A TSP, DSP, or their agent shall implement these instructions if distribution voltage reduction measures are available and already installed. If the TSP, DSP, or their agent determines in their sole discretion that the distribution voltage reduction would adversely affect reliability, the voltage reduction measure may be reduced, modified, or otherwise changed from maximum performance to a level of exercise that has no negative impact to reliability.

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

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

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

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

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

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

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

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

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

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

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

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

(3) ERCOT may declare an EEA Level 3 when the clock-minute average system frequency falls below 59.91 Hz for 20 consecutive minutes or when steady-state frequency falls below 59.8 Hz. ERCOT will declare an EEA Level 3 when PRC cannot be maintained above 1,500 MW or when the clock-minute average system frequency falls below 59.91 Hz for 25 consecutive minutes. Upon declaration of an EEA Level 3, ERCOT shall take any of the following measures as necessary to recover frequency or PRC to the minimum required levels:

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

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

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

(b) Direct all TOs to shed firm Load, in 100 MW blocks, distributed as documented in the Operating Guides in order to maintain a steady state system frequency at a minimum of 59.91 Hz and to recover 1,500 MW of PRC within 30 minutes.

(i) TOs and TDSPs may:

(A) Manually shed Load connected to under-frequency relays and/or under-voltage relays pursuant to an ERCOT Load shed directive issued during EEA Level 3 so long as the TO has determined that system conditions warrant utilizing Load connected to under-frequency and/or under-voltage relays and each affected TO continues to comply with its Under-Frequency Load Shed (UFLS) obligation as described in Nodal Operating Guide Section 2.6.1, Automatic Firm Load Shedding, and its Load shed obligation as described in Nodal Operating Guide Section 4.5.3.4, Load Shed Obligation.

(B) Manually shed Load that is armed to deploy as part of the 58.5 Hz, 58.7 Hz, and anti-stall UFLS stages, such that the UFLS Load falls below the TO's 25% Load relief obligation, as described in Nodal Operating Guide Section 2.6.1, in order to meet ERCOT operating instructions for manual Load shed if all Load identified for manual Load shed and the Load identified in paragraph (A) above has been shed.

(c) Implement any appropriate measures associated with EEA Levels 1 and 2 that have not already been implemented.

ERCOT Impact Analysis Report

NPRR Number	1221	NPRR Title	Related to NOGRR262, Provisions for Operator-Controlled Manual Load Shed
Impact Analysis Date	March 20, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon implementation of Nodal Operating Guide Revision Request (NOGRR) 262, Provisions for Operator-Controlled Manual Load Shed.		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	ERCOT will update its business processes to implement this NPRR.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NPRR beyond what was captured in the Impact Analysis for NOGRR262.

Board Report

NPRR Number	**1227**	**NPRR Title**	**Related to RMGRR181, Alignment of Defined Term Usage and Resolution of Inconsistencies**
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	The first of the month following Public Utility Commission of Texas (PUCT) approval		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	2.1, Definitions 15.1.1.7, Completion of Switch Request and Effective Switch Date 15.1.3.2, Acquisition Transfer Process 15.1.3.3, Customer Billing Contact Information 15.1.7, Move In or Move Out Date Change 15.2, Database Queries 16.1.1, Re-Registration as a Market Participant 19.3.1, Defined Texas Standard Electronic Transactions 23, Form B, Load Serving Entity (LSE) Application for Registration		
Related Documents Requiring Revision/Related Revision Requests	Retail Market Guide Revision Request (RMGRR) 181, Alignment of Defined Term Usage and Resolution of Inconsistencies		
Revision Description	This Nodal Protocol Revision Request (NPRR) aligns defined term usage in the Protocols with Section 2.1 and adds five definitions (‘Acquisition Transfer’, ‘Decision’, ‘Effective Date’, ‘Gaining Competitive Retailer (CR)’, and ‘Losing Competitive Retailer (CR)’) that were previously located in Retail Market Guide Sections 2.1, Definitions, and 7.11.2, Acquisition and Transfer of Customers from one Retail Electric Provider to Another. This NPRR also replaces the broadly titled terms ‘Decision’ and ‘Effective Date’ with the specific terms ‘Mass Transition Decision’, ‘Acquisition Transfer Decision’, ‘Mass Transition Effective Date’, and ‘Acquisition Transfer Effective Date’ to provide additional clarity. Finally, this NPRR expands the definitions of Gaining Competitive Retailer (CR) and		

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	Losing Competitive Retailer (CR) to apply beyond the Mass Transition and Acquisition Transfer processes.
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvements ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	This NPRR accompanies RMGRR181, which clarifies language in the Retail Market Guide to aid readability, increase consistency, and reduce the risk of misinterpretation. This NPRR causes no impact to the market as it is not a process change.
PRS Decision	On 6/13/24, PRS voted unanimously to recommend approval of NPRR1227 as submitted. All Market Segments participated in the vote. On 7/18/24, PRS voted unanimously to endorse and forward to TAC the 6/13/24 PRS Report and 4/30/24 Impact Analysis for NPRR1227. All Market Segments participated in the vote.
Summary of PRS Discussion	On 6/13/24, PRS reviewed NPRR1227 and the 6/4/24 RMS comments. On 7/18/24, PRS reviewed the 4/30/24 Impact Analysis for NPRR1227.
TAC Decision	On 7/31/24, TAC voted unanimously to table NPRR1227. All Market Segments participated in the vote. On 8/28/24, TAC voted unanimously to recommend approval of NPRR1227 as recommended by PRS in the 7/18/24 PRS Report. All Market Segments participated in the vote.

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Summary of TAC Discussion	On 7/31/24, TAC referenced RMGRR181 currently at RMS. On 8/28/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NPRR1227 as recommended by TAC in the 8/28/24 TAC Report.

Opinions	
Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1227 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1227.
ERCOT Opinion	ERCOT supports approval of NPRR1227.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1227 and believes that it provides a positive market impact by offering process improvements by relocating four, shared-use definitions from the Retail Market Guide to the Protocols; and by aligning defined term usage throughout the Protocols.

Sponsor	
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Company	ERCOT
Phone Number	512-248-6521

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Cell Number	
Market Segment	Not Applicable

Market Rules Staff Contact	
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Comments Received	
Comment Author	**Comment Summary**
RMS 060424	Endorsed NPRR1227 as submitted

Market Rules Notes

None

Proposed Protocol Language Revision

2.1 DEFINITIONS

Acquisition Transfer

The process used to transfer Electric Service Identifiers (ESI IDs) from the current Competitive Retailer (CR) to another CR(s) as a result of an acquisition pursuant to P.U.C. SUBST. R. 25.493, Acquisition and Transfer of Customers from one Retail Electric Provider to Another.

Acquisition Transfer Decision

Parameters associated with an Acquisition Transfer event that dictate the parties involved and the desired Acquisition Transfer Effective Date. Acquisition Transfer Decision parameters include designation of the Losing CR, the Gaining CR, the preliminary list of transitioning ESI IDs, the method of transfer, and the desired Acquisition Transfer Effective Date. The desired Acquisition Transfer Effective Date may be modified by agreement among Market Participants based on the volume of transitioning ESI IDs and the Transmission and/or Distribution Service Provider's (TDSP's) capacity to read meters and process transactions involving manual intervention.

Acquisition Transfer Effective Date

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

Competitive Retailer (CR)

A Municipally Owned Utility (MOU) or an Electric Cooperative (EC) that offers Customer Choice and sells electric energy at retail in the restructured electric power market in Texas, or a Retail Electric Provider (REP).

Gaining Competitive Retailer (CR)

CR that becomes the REP of record upon the processing of the transition of an Electric Service Identifier (ESI ID) from one REP of record to another. This includes the CR identified in the initiating Mass Transition Decision or Acquisition Transfer Decision that is to become the REP of record as of the Mass Transition Effective Date or Acquisition Transfer Effective Date for a transitioned Electric Service Identifier (ESI ID) following the Mass Transition or Acquisition Transfer.

Losing Competitive Retailer (CR)

CR that is removed as the REP of record upon the processing of the transition of an ESI ID from one REP of record to another. This includes the CR identified in the initiating Mass Transition Decision or Acquisition Transfer Decision that is to be removed as the REP of record upon the processing of a Mass Transition or Acquisition Transfer transaction.

Mass Transition

The transition of Electric Service Identifiers (ESI IDs) from one Competitive Retailer (CR) to a Provider of Last Resort (POLR) or designated CR, or from one Transmission and/or Distribution Service Provider (TDSP) to another TDSP, in a quantity or within a timeframe identified by Applicable Legal Authority.

Mass Transition Decision

Parameters associated with a Mass Transition event that dictate the parties involved and the Mass Transition Effective Date. Mass Transition Decision parameters include designation of the Losing CR, the Gaining CR, the preliminary list of transitioning ESI IDs, and the Mass Transition Effective Date.

Mass Transition Effective Date

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

15.1.1.7 Completion of Switch Request and Effective Switch Date

(1) A Switch Request is effectuated on the actual meter read date in the 867_04, Initial Meter Read, or the final 867_03, Monthly or Final Usage, which must be equal to the scheduled meter read date. The process for a specific Switch Request is complete upon receipt of the effectuating meter read sent by the TDSP. The TDSP shall send the meter read information to ERCOT using the 867_03 transaction and 867_04 transaction within three Retail Business Days of the meter read. This transaction will contain an effectuating meter read indicator. If the TDSP has made every reasonable effort to get the actual data for the meter read and absolutely cannot, the TDSP may estimate the reading for the ESI ID, regardless of the meter type or Customer class. When an estimate occurs on a demand meter, the demand indicator has not been reset. Upon receipt, ERCOT will send final meter read information to the current CR DUNS Number provided in the 867_03 transaction by the TDSP and initial meter read information to the new CR DUNS Number provided in the 867_04 transaction by the TDSP using the 867_03 transaction and 867_04 transaction, as appropriate. Meter reads will be sent to the CR DUNS Number within the Texas Standard Electronic Transaction (TX SET) transaction from the TDSP within 12 hours of receipt by ERCOT.

(2) Failure by ERCOT to provide the initial meter read information does not change the Mass Transition ~~effective~~ Effective ~~date~~ Date of the switch.

(3) Switches shall become effective at 0000 (midnight) on the actual date of the effectuating meter read. The new CR may request a special meter read (including a profile-estimated meter read or interval meter calculation as allowed), in accordance with the TDSP's tariff. For a special meter read, the switch is effective at 0000 (midnight) the day of the special meter read. During the switch process, the Customer will continue to be served by its current CR.

15.1.3.2 Acquisition Transfer Process

(1) In an ~~acquisition~~ Acquisition ~~transfer~~ Transfer event, ERCOT shall submit the 814_03, Enrollment Notification Request, requesting a meter read for the associated ESI IDs. The 814_03 transaction shall contain a request for historical usage and the requested date or FASD for the meter read date to transfer the ESI IDs. If an actual meter read cannot be obtained by the date requested in the 814_03 transaction, then the meter read may be estimated by the TDSP.

(2) The TDSP shall respond to the 814_03 transaction within two Retail Business Days with an 814_04, Enrollment Notification Response, and an 867_02, Historical Usage. Within one Retail Business Day of receiving the 814_04 transaction, ERCOT will send an 814_11, Drop Response, to the transitioning CR and forward an 814_14, Drop Enrollment Request, with the scheduled meter read date, to the designated CR. The TDSP shall submit an 867_04, Initial Meter Read, with a meter read date equal to the scheduled meter read date in the 814_04 transaction, which will also be known as the

transition date. See Retail Market Guide Section 9, Appendices, Appendix D1, Transaction Timing Matrix, for specific transaction timings.

(3) For a detailed outline of the business process and responsibilities of all Entities involved in an ~~acquisition~~ Acquisition ~~transfer~~ Transfer event, refer to the Retail Market Guide Section 7, Market Processes.

15.1.3.3 Customer Billing Contact Information

(1) All CRs participating in the Texas retail electric market shall provide, in accordance with the Retail Market Guide, current Customer billing contact information to ERCOT for use in the event of a Mass Transition. ERCOT shall retain the Customer data from the most recent submission, to be used in lieu of data from the exiting CR, in instances where the exiting CR does not provide data. When a Mass Transition occurs, ERCOT shall provide the ~~gaining~~ Gaining CRs with available Customer billing contact information for the ESI IDs the ~~gaining~~ Gaining CRs will be obtaining through the Mass Transition event. During a Mass Transition event, ERCOT shall also provide the TDSPs with available Customer contact information.

(2) For a detailed outline of the process, refer to the Retail Market Guide Section 7, Market Processes.

15.1.7 Move In or Move Out Date Change

(1) The CR will send a date change transaction using the 814_12, Date Change Request. ERCOT will accept date changes on or before the day preceding the scheduled move in or move out. ERCOT will reject any 814_12 transaction received on the scheduled move in or move out date, as well as date change requests on orders that were scheduled in the past.

(2) If the date change does not pass validation, ERCOT will reply to the CR with a rejection of the date change transaction using the 814_13, Date Change Response, within two Retail Business Hours of receipt of the 814_12 transaction with the exception of a date change that is invalid because of "Item or Service Not Established." In the case of "Item or Service Not Established," ERCOT will hold the date change request and continue to retry the request at regular intervals for 48 hours counting only hours on Retail Business Days, but not only Business Hours.

(3) If the date change is accepted, ERCOT will notify the TDSP using the 814_12 transaction within two Retail Business Hours of receipt of the 814_12 transaction from the CR. The TDSP will respond within two Retail Business Days using the 814_13 transaction. If the TDSP accepts the date change, the submitting CR is notified via the 814_13 transaction and the other CR is notified via the 814_12 transaction. ERCOT will only send the 814_12 transaction to the ~~losing~~ Losing CR on a move in if ERCOT has already sent the 814_06, Loss Notification, to the ~~losing~~ Losing CR. ERCOT will only send the 814_12 transaction to the ~~gaining~~ Gaining CR on a move out to CSA if ERCOT has already sent

the 814_22, CSA CR Move In Request, to the CSA CR.

15.2 Database Queries

(1) Market Participants may obtain information from ERCOT to determine or to verify the Electric Service Identifier (ESI ID) for a Service Delivery Point. The following information can be obtained through a database query or an extract on the ERCOT website:

(a) Service Address;

(b) Meter read code;

(c) ESI ID;

(d) Transmission and/or Distribution Service Provider (TDSP);

(e) Premise type;

(f) Current status (active/de-energized/inactive) with effective date;

(g) Move in/move out pending flag with associated date, if applicable;

(h) Power region;

(i) Station ID;

(j) Metered/unmetered flag;

(k) ESI ID dates that include:

(i) Eligibility date;

(ii) Start date;

(iii) Create date; and

(iv) Retire date;

(l) Provider of Last Resort (POLR) Customer class as defined in subsection (c) of P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR);

(m) Settlement Advanced Metering System (AMS) meter or Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ Interval Data Recorder (IDR) indicator that provides a true/false value as determined by ERCOT's system evaluation of the current Load Profile ID assignment of an ESI ID;

(n) TDSP AMS indicator that is assigned by the TDSP to denote the following:

(i) AMSR – an AMS meter or MOU/EC Non-BUSIDRRQ IDR with remote connect and disconnect capability;

(ii) AMSM - an AMS meter or MOU/EC Non-BUSIDRRQ IDR without remote connect and disconnect capability; or

(iii) Null – neither an AMS meter type nor an MOU/EC Non-BUSIDRRQ IDR exists at this Premise; and

(o) Switch hold indicator.

[NPRR1095: Replace paragraph (1) above with the following upon system implementation:]

(1) Market Participants may obtain information from ERCOT to determine or to verify the Electric Service Identifier (ESI ID) for a Service Delivery Point. The following information can be obtained through a database query, an extract, or an Application Programming Interface (API) on the ERCOT website:

(a) Service Address;

(b) Meter read code;

(c) ESI ID;

(d) Transmission and/or Distribution Service Provider (TDSP);

(e) Premise type;

(f) Current status (active/de-energized/inactive) with effective date;

(g) Move in/move out pending flag with associated date, if applicable;

(h) Power region;

(i) Station ID;

(j) Metered/unmetered flag;

(k) ESI ID dates that include:

(i) Eligibility date;

(ii) Start date;

(iii) Create date; and

(iv) Retire date;

(l) Provider of Last Resort (POLR) Customer class as defined in subsection (c) of P.U.C. SUBST. R. 25.43, Provider of Last Resort (POLR);

(m) Settlement Advanced Metering System (AMS) meter or Municipally Owned Utility (MOU) / Electric Cooperative (EC) Non-BUSIDRRQ Interval Data Recorder (IDR) indicator that provides a true/false value as determined by ERCOT's system evaluation of the current Load Profile ID assignment of an ESI ID;

(n) TDSP AMS indicator that is assigned by the TDSP to denote the following:

(i) AMSR – an AMS meter or MOU/EC Non-BUSIDRRQ IDR with remote connect and disconnect capability;

(ii) AMSM – an AMS meter or MOU/EC Non-BUSIDRRQ IDR without remote connect and disconnect capability; or

(iii) Null – neither an AMS meter type nor an MOU/EC Non-BUSIDRRQ IDR exists at this Premise; and

(o) Switch hold indicator;

(p) County; and

(q) Metered service type.

(2) At least daily, ERCOT will provide all of the attributes listed above when an 814_20, ESI ID Maintenance Request, is received and accepted by ERCOT that creates an ESI ID, or makes changes to the switch hold or the provisioned AMS meter indicator of an ESI ID.

16.1.1 Re-Registration as a Market Participant

(1) Any Market Participant that has had one of the following occur must provide to ERCOT a new DUNS Number (DUNS #) to re-register as a Market Participant with ERCOT:

(a) Its Agreement with ERCOT terminated;

(b) Its Customers dropped to the Provider(s) of Last Resort (POLR(s)) pursuant to Section 15.1.3, Transition Process; or

(c) Its Customers dropped to a ~~gaining~~ Gaining Competitive Retailer (CR) pursuant to Section 15.1.3.

19.3.1 Defined Texas Standard Electronic Transactions

(1) **Service Order Request (650_01)**

This transaction set:

(a) From the Competitive Retailer (CR) to the Transmission and/or Distribution Service Provider (TDSP) via point to point protocol, is used to initiate the original service order request, cancel request, or change/update request.

(b) For every 650_01, Service Order Request, there will be a 650_02, Service Order Response.

(2) **Service Order Response (650_02)**

This transaction set:

(a) From the TDSP to the CR via point to point protocol, is used to send a response to the CR's original 650_01, Service Order Request, that the transaction is complete, complete unexecutable, rejected, or requires a permit.

(b) For every 650_01 transaction, there will be a 650_02 transaction.

(3) **Planned or Unplanned Outage Notification (650_04)**

This transaction set:

(a) From the TDSP to the CR via point to point protocol, is used to notify the CR of a suspension of delivery service or to cancel the suspension of delivery service.

(b) From Municipally Owned Utility/Electric Cooperative (MOU/EC) TDSP to CR via point to point protocol, is used to notify the CR of disconnect/reconnect of delivery service for non-payment of wires charges, unless otherwise indicated in Retail Market Guide Section 8.1, Municipally Owned Utility and/or Electric Cooperative Transmission and/or Distribution Service Provider Market.

(4) **Planned or Unplanned Outage Response (650_05)**

This transaction set is no longer valid as of Texas Standard Electronic Transaction (SET) 4.0.

(5) **TDSP Invoice (810_02)**

This transaction set:

From the TDSP to the CR via point to point protocol, is an invoice for wire charges as listed in each TDSP tariff (i.e., delivery charges, late payment charges, discretionary service charges, etc.). The 810_02, TDSP Invoice, may be paired with an 867_03, Monthly or Final Usage, to trigger the Customer billing process.

(6) **MOU/EC Invoice (810_03)**

This transaction set:

From the CR to the MOU/EC TDSP via point to point protocol, is an invoice for monthly energy charges, discretionary, and service charges for the current billing period, unless otherwise indicated in Retail Market Guide Section 8.1. The 810_03, MOU/EC Invoice, will be preceded by an 867_03, Monthly or Final Usage, to trigger the Customer billing process.

(7) **Maintain Customer Information Request (814_PC)**

This transaction set:

(a) From a CR to the TDSP via point to point protocol, is used to maintain the information needed by the TDSP to verify the CR's end use Customer's identity (i.e., name, address and contact phone number) for a particular point of delivery served by the CR. A CR shall be required to provide TDSP with the information to contact the Customer and to continuously provide TDSP updates of changes in such information.

(b) From the CR to the TDSP via point to point protocol, will be transmitted only after the CR has received the 867_04, Initial Meter Read, from the TDSP for that specific move in Customer. Also, the CR will not transmit this transaction set and/or provide any updates to the TDSP after receiving the 867_03, Monthly or Final Usage, final meter read for that specific move out Customer.

(c) From a MOU/EC TDSP to CR via point to point protocol, is used to provide the CR with updated Customer information (name, address, membership ID, home phone number, etc.) for a particular point of delivery served by both the MOU/EC TDSP and the CR and to continuously provide CR updates of such information, unless otherwise indicated in Retail Market Guide Section 8.1.

(8) **Maintain Customer Information Response (814_PD)**

This transaction set:

From the TDSP to the CR via point to point protocol, or from the CR to MOU/EC TDSP via point to point protocol, unless otherwise indicated in Retail Market Guide Section 8.1, is used to respond to the 814_PC, Maintain Customer Information Request.

(9) **Switch Request (814_01)**

This transaction set:

From a new CR to ERCOT, is used to begin the Customer enrollment process for a switch.

(10) **Switch Reject Response (814_02)**

This transaction set:

From ERCOT to the new CR, is used by ERCOT to reject the 814_01, Switch Request, based on incomplete or invalid information. This is a conditional transaction and will only be used as a negative response. If the 814_02, Switch Reject Response, is not received from ERCOT, the new CR will receive the 814_05, CR Enrollment Notification Response, from ERCOT.

(11) **Enrollment Notification Request (814_03)**

This transaction set:

(a) From ERCOT to the TDSP, passes information from the 814_01, Switch Request; 814_16, Move In Request; or an 814_24, Move Out Request, where a Continuous Service Agreement (CSA) exists.

(b) The historical usage, if requested by the submitter of the initiating transaction, will be sent using the 867_02, Historical Usage.

(c) Will be initiated by ERCOT and transmitted to the TDSP in the event of a Mass Transition.

(d) Will be initiated by ERCOT and transmitted to the TDSP in the event of an ~~acquisition~~ Acquisition ~~transfer~~Transfer.

(12) **Enrollment Notification Response (814_04)**

This transaction set:

From the TDSP to ERCOT, is used to provide the scheduled meter read date that the TDSP has calculated and pertinent Customer and Premise information in response to an 814_01, Switch Request; 814_16, Move In Request; 814_24, Move Out Request, where a CSA exists initiated by a CR or a Mass Transition or ~~acquisition~~ Acquisition ~~transfer~~ Transfer of Electric Service Identifiers (ESI IDs) initiated by ERCOT. TDSPs will acknowledge the initiating CRs request for historical usage with this transaction but will send the usage using the 867_02, Historical Usage.

(13) **CR Enrollment Notification Response (814_05)**

This transaction set:

From ERCOT to the new CR, is essentially a pass through of the TDSP's 814_04, Enrollment Notification Response, information. This transaction will provide the scheduled meter read date for the CR's 814_01, Switch Request, or 814_16, Move In Request.

(14) **Loss Notification (814_06)**

This transaction set:

From ERCOT to the current CR, is used to notify a current CR of a drop initiated by an 814_01, Switch Request, or drop notification due to a pending 814_16, Move In Request, from a new CR.

(15) **Loss Notification Response (814_07)**

This transaction set is no longer valid as of Texas SET 4.0.

(16) **Cancel Request (814_08)**

This transaction set:

(a) From ERCOT to the TDSP, is used to cancel an 814_03, Enrollment Notification Request, or an 814_24, Move Out Request.

(b) From ERCOT to the current CR, is used to cancel an 814_06, Loss Notification, (forced Move-Out or Switch Request), an 814_24 transaction, or an 814_11, Drop Response.

(c) From ERCOT to the new CR, is used to cancel an 814_01, Switch Request, an 814_16, Move In Request, or an 814_14, Drop Enrollment Request.

(d) From the current CR to ERCOT, is used to cancel an 814_24 transaction.

(e) From the new CR to ERCOT, is used to cancel an 814_01 or an 814_16 transaction.

(f) From ERCOT to the CSA CR, is used to cancel an 814_22, CSA CR Move In Request.

(g) From ERCOT to the requesting CR/Provider of Last Resort (POLR), is used to cancel pending transactions involved in a Mass Transition.

(h) From ERCOT to the ~~gaining~~ Gaining CR, is used to cancel pending transaction involved in an ~~acquisition~~ Acquisition ~~transfer~~Transfer.

(17) **Cancel Response (814_09)**

This transaction set:

(a) From the TDSP to ERCOT, is used in response to the cancellation of an 814_03, Enrollment Notification Request, or an 814_24, Move Out Request.

(b) From the current CR to ERCOT, is no longer valid as of Texas SET 4.0.

(c) From the new CR to ERCOT, is no longer valid as of Texas SET 4.0.

(d) From ERCOT to the current CR, is used in forwarding the response of the Customer cancel of an 814_24 transaction.

(e) From CSA CR to ERCOT, is no longer valid as of Texas SET 4.0.

(f) From ERCOT to the submitter of an 814_08, Cancel Request, is used to reject the cancellation request.

(g) From POLR to ERCOT, is no longer valid as of Texas SET 4.0.

(18) **Drop Request (814_10)**

This transaction set is no longer valid as of March 8, 2007 (Reference Project No. 33025, PUC Rulemaking Proceeding to Amend Commission Substantive Rules Consistent With §25.43, Provider of Last Resort (POLR)).

(19) **Drop Response (814_11)**

This transaction set:

(a) From ERCOT to the current CR, is sent within one Retail Business Day to notify the CR that the request is invalid.

(b) From ERCOT to the current CR, is used in response to a Mass Transition.

(c) From ERCOT to the current CR, is used in response to an ~~a~~Acquisition ~~transition~~Transfer.

(20) **Date Change Request (814_12)**

This transaction set:

(a) From new CR to ERCOT, is used when the Customer requests a date change to the original 814_16, Move In Request.

(b) From ERCOT to the current CR, is used for a notification of the date change on the 814_16 transaction, from the new CR.

(c) From ERCOT to the TDSP, is used for notification of a move in or move out date change request.

(d) From the current CR to ERCOT, is used when the Customer requests a date change to the original 814_24, Move Out Request.

(e) From ERCOT to the new CR, is used for notification of the date change on the 814_24 transaction from the current CR.

(f) From ERCOT to the CSA CR, is used for notification of the date change on the 814_24 transaction only.

(21) **Date Change Response (814_13)**

This transaction set:

(a) From ERCOT to new CR, is used to respond to the requested date change to the original move in date on the 814_12, Date Change Request.

(b) From the current CR to ERCOT, is no longer valid as of Texas SET 4.0.

(c) From the CSA CR to ERCOT, is no longer valid as of Texas SET 4.0.

(d) From the TDSP to ERCOT, is used to respond to the requested date change to the original move in or move out date on the 814_12 transaction.

(e) From ERCOT to the current CR, is used to respond to the requested date change to the original move out date on the 814_12 transaction.

(f) From the new CR to ERCOT, is no longer valid as of Texas SET 4.0.

(22) **Drop Enrollment Request (814_14)**

This transaction set:

(a) From ERCOT to the POLR or designated CR, is used in response to a Mass Transition.

(b) From ERCOT to the ~~gaining~~ Gaining CR, is used in response to an ~~acquisition~~ Acquisition ~~transfer~~Transfer.

(23) **Drop Enrollment Response (814_15)**

This transaction set is no longer valid as of Texas SET 4.0.

(24) **Move In Request (814_16)**

This transaction set:

From the new CR to ERCOT, is used to begin the Customer enrollment process for a move in.

(25) **Move In Reject Response (814_17)**

This transaction set:

From ERCOT to the new CR, is used by ERCOT to reject the 814_16, Move In Request, based on incomplete or invalid information. This is a conditional transaction and will only be used as a negative response. If the 814_17, Move In Reject Response, is not received from ERCOT, the CR will receive the 814_05, CR Enrollment Notification Response.

(26) **Establish/Delete CSA Request (814_18)**

This transaction set:

(a) From the new CSA CR to ERCOT, is used to establish the owner/landlords' new CSA CR in the registration system.

(b) From the current CSA CR to ERCOT, is used to remove an existing CSA CR from the registration system.

(c) From ERCOT to the current CSA CR, is used for notification that the owner/landlord has selected a new CSA CR.

(d) From ERCOT to the MOU/EC TDSP, is used to validate the CSA relationship information in the MOU/EC TDSP's system, unless otherwise indicated in Retail Market Guide Section 8.1.

(e) From ERCOT to the MOU/EC TDSP, is used for notification of CSA deletion, unless otherwise indicated in Retail Market Guide Section 8.1.

[NPRR1168: Replace paragraph (26) above with the following upon system implementation of RMGRR172:]

(26) **Establish/Change/Delete CSA Request (814_18)**

This transaction set:

(a) From the new CSA CR to ERCOT, is used to establish the owner/landlords' new CSA CR in the registration system.

(b) From the current CSA CR to ERCOT, is used to change an existing CSA CR end date.

(c) From the current CSA CR to ERCOT, is used to remove an existing CSA CR from the registration system.

(d) From ERCOT to the current CSA CR, is used for notification that the owner/landlord has selected a new CSA CR.

(e) From ERCOT to the MOU/EC TDSP, is used to validate the CSA relationship information in the MOU/EC TDSP's system, unless otherwise indicated in Retail Market Guide Section 8.1.

(f) From ERCOT to the MOU/EC TDSP, is used for notification of a change in CSA end date, unless otherwise indicated in Retail Market Guide Section 8.1, Municipally Owned Utility and/or Electric Cooperative Transmission and/or Distribution Service Provider Market.

(g) From ERCOT to the MOU/EC TDSP, is used for notification of CSA deletion, unless otherwise indicated in Retail Market Guide Section 8.1.

(27) **Establish/Delete CSA Response (814_19)**

This transaction set:

(a) From ERCOT to the new CSA CR, is used to respond to the 814_18, Establish/Delete CSA Request, enrolling the new CSA CR in the registration system.

(b) From ERCOT to the current CSA CR, is used to respond to the 814_18 transaction deleting the current CR from the registration system.

(c) From the current CSA CR to ERCOT, is no longer valid as of Texas SET 4.0.

(d) From the MOU/EC TDSP to ERCOT, is used to provide a response to the 814_18 transaction, unless otherwise indicated in Retail Market Guide Section 8.1.

[NPRR1168: Replace paragraph (27) above with the following upon system implementation of RMGRR172:]

(27) **Establish/Change/Delete CSA Response (814_19)**

This transaction set:

(a) From ERCOT to the new CSA CR, is used to respond to the 814_18, Establish/Change/Delete CSA Request, enrolling the new CSA CR in the registration system.

(b) From ERCOT to the new CSA CR, is used to respond to the 814_18 transaction changing the end date for the current CSA CR in the registration system.

(c) From ERCOT to the current CSA CR, is used to respond to the 814_18 transaction deleting the current CR from the registration system.

(d) From the current CSA CR to ERCOT, is no longer valid as of Texas SET 4.0.

(e) From the MOU/EC TDSP to ERCOT, is used to provide a response to the 814_18 transaction, unless otherwise indicated in Retail Market Guide Section 8.1.

(28) **ESI ID Maintenance Request (814_20)**

This transaction set:

(a) From the TDSP to ERCOT, is used to initially populate the registration system for conversion/opt-in.

(b) From the TDSP to ERCOT, is used to communicate the addition of a new ESI ID, changes to information associated with an existing ESI ID, or retirement of an existing ESI ID.

(c) From ERCOT to current CR and any pending CR(s), is notification of the TDSP's changes to information associated with an existing ESI ID.

(29) **ESI ID Maintenance Response (814_21)**

This transaction set:

(a) From ERCOT to TDSP, is used to respond to the 814_20, ESI ID Maintenance Request.

(b) From the current CR and any pending CR(s) to ERCOT, is no longer valid as of Texas SET 4.0.

(c) From the new CR to ERCOT, is no longer valid as of Texas SET 4.0.

(30) **CSA CR Move In Request (814_22)**

This transaction set:

From ERCOT to CSA CR, is used to start a CSA service for the ESI ID.

(31) **CSA CR Move In Response (814_23)**

This transaction set:

From the CSA CR to ERCOT, is no longer valid as of Texas SET 4.0.

(32) **Move Out Request (814_24)**

This transaction set:

(a) From the current CR to ERCOT, is used for notification of a Customer's ~~moveout~~ Move-Out ~~request~~Request.

(b) From ERCOT to the TDSP, is notification of the Customer's ~~move~~ Move-~~out~~ Out ~~request~~Request. If a CSA exists on the ESI ID, then the 814_03, Enrollment Notification Request, is sent instead of the 814_24, Move Out Request.

(33) **Move Out Response (814_25)**

This transaction set:

(a) From the TDSP to ERCOT to the current CR, is used to respond to the 814_24, Move Out Request. If a CSA exists on the ESI ID and ERCOT sent the 814_03, Enrollment Notification Request, instead of the 814_24 transaction, the TDSP will then respond with the 814_04, Enrollment Notification Response.

(b) From ERCOT to the current CR, is used to respond to the 814_24 transaction.

(34) **Historical Usage Request (814_26)**

This transaction set:

(a) From the current CR to ERCOT, is used to request the historical usage for an ESI ID.

(b) From ERCOT to the TDSP, it is a pass through of the current CR's 814_26, Historical Usage Request.

(35) **Historical Usage Response (814_27)**

This transaction set:

(a) From the TDSP to ERCOT, is used to respond to the 814_26, Historical Usage Request.

(b) From ERCOT to the current CR, is a pass through of the TDSP's response to the 814_26 transaction.

(36) **Complete Unexecutable or Permit Required (814_28)**

This transaction set:

(a) For a move out, is from the TDSP to ERCOT, and from ERCOT to the current CR, to notify the current CR the move out was unexecutable. Upon sending this transaction, the TDSP closes the initiating move out transaction. The CR must initiate corrective action and resubmit the Move-Out Request.

(b) For a move in, is from the TDSP to ERCOT, and from ERCOT to the new CR, or the current CR for energized accounts, to notify the CR that the work was complete unexecutable, or that a permit is required. Upon sending this transaction to notify the new CR of a complete unexecutable, the TDSP closes the initiating transaction. The new CR must initiate corrective action and resubmit the Move-In Request.

(c) Upon sending the 814_28 (PT) transaction to notify the new CR that a permit is required, ERCOT will allow the TDSP 20 Retail Business Days to send the 814_04, Enrollment Notification Response, due to permit requirements. After the 20 Retail Business Days, if no 814_04 transaction is received, ERCOT will then issue an 814_08, Cancel Request. If the move in is cancelled due to permit not received, ERCOT will note the reason in the 814_08 transaction.

(d) For a switch, is from the TDSP to ERCOT, and from ERCOT to the new CR or current CR, to notify CRs that the work has been complete unexecutable.

(37) **Complete Unexecutable or Permit Required Response (814_29)**

This transaction set:

(a) From ERCOT to the TDSP to reject the 814_28, Complete Unexecutable or Permit Required.

(b) From the CR (current CR for a move out or a new CR for a move in) to ERCOT, and from ERCOT to the TDSP is no longer valid as of Texas SET 4.0.

(38) **CR Remittance Advice (820_02)**

This transaction set:

(a) From the CR to the TDSP, is used as a remittance advice concurrent with a corresponding payment to the TDSP banking institution for a dollar amount equal to the total of the itemized payments in the 820_02, CR Remittance Advice. This transaction will reference the 810_02, TDSP Invoice, by ESI ID. If payment and remittance are transmitted together to a financial institution, this implementation guide may be used as a baseline for discussion with the payer's financial institution. All "must use" fields in the 820_02 transaction must be forwarded to the payer's financial institution and be supported by the payee's financial institution.

(b) A single payment sent via the bank and a single remittance sent to the TDSP can include multiple invoices, however a one to one correlation must exist between the payment submitted to the bank and the corresponding remittance advice to the TDSP.

(39) **MOU/EC Remittance Advice (820_03)**

This transaction set:

From the MOU/EC TDSP to the CR, is used as a remittance advice concurrent with a corresponding payment to the CR banking institution for a dollar amount equal to the total of the itemized payments in the 820_03, MOU/EC Remittance Advice, unless otherwise indicated in Retail Market Guide Section 8.1. This transaction will reference the CR's Customer account number and ESI ID. If payment and remittance are transmitted together to a financial institution, this implementation guide may be used as a baseline for discussion with the payer's financial institution. All "must use" fields in the 820_03 transaction, must be forwarded to the payer's financial institution and be supported by the payee's financial institution.

(40) **Invoice or Usage Reject Notification (824)**

This transaction set:

(a) From the CR to the TDSP, is used by the CR to reject and/or accept with exception the 810_02, TDSP Invoice, sent by the TDSP.

(b) From ERCOT to the TDSP, is used to reject the 867_03, Monthly or Final Usage, transaction sent by the TDSP.

(c) From the CR to ERCOT, is used to reject the 867_03 transaction sent by ERCOT.

(d) From the MOU/EC TDSP to the CR, is used to reject the 810_03, MOU/EC Invoice, sent by the CR, unless otherwise indicated in Retail Market Guide Section 8.1.

(41) **Historical Usage (867_02)**

This transaction set:

(a) From the TDSP to ERCOT, is used to report historical usage.

(b) From ERCOT to the CR, is essentially a pass through of the TDSP's 867_02, Historical Usage.

(42) **Monthly or Final Usage (867_03)**

This transaction set:

(a) From the TDSP to ERCOT, is used to report monthly usage.

(b) From ERCOT to the CR, is essentially a pass through of the TDSP's 867_03, Monthly or Final Usage.

(c) From ERCOT to the TDSP or CR, is for ERCOT polled services.

(43) **Initial Meter Read (867_04)**

This transaction set:

(a) From the TDSP to ERCOT, is used to report the initial read associated with an 814_01, Switch Request, or an 814_16, Move In Request.

(b) From ERCOT to the new CR, is used to report the initial read associated with an 814_01 or 814_16 transaction.

(44) **Functional Acknowledgement (997)**

This transaction set:

(a) From the receiver of the originating transaction to the sender of the originating transaction, is used to acknowledge the receipt of the originating transaction and indicate whether the transaction passed American National Standards Institute Accredited Standards Committee X12 (ANSI ASC X12) validation. This acknowledgement does not imply that the originating transaction passed TX SET validation. The CR, TDSP, or ERCOT shall respond with a 997, Functional Acknowledgement, within 24 hours of receipt of an inbound transaction.

(b) Provides a critical audit trail. All parties must send a 997 transaction for all Electronic Data Interchange (EDI) transactions. Parties will track and monitor acknowledgements sent and received.

(45) **Option 1 Outages: Outage Status Request (T0)**

This transaction set:

From a CR to TDSP, is used to request outage status. This is not a required transaction for an Option 1 CR reporting unplanned outages.

(46) **Option 1 Outages: Trouble Reporting Request (T1)**

This transaction set:

From a CR to TDSP, is used to report an outage or service irregularity requiring near Real-Time outage response. This is a required transaction for an Option 1 CR to electronically transmit to the TDSP for every valid outage or service irregularity reported.

(47) **Option 1 Outages: Trouble Report Acknowledgement (T2)**

This transaction set:

From a TDSP to CR, is used to acknowledge the receipt of a T1, Option 1 Outages: Trouble Reporting Request, with either an acceptance or a rejection response. This is a required transaction for the TDSP when an Option 1 CR utilizes the T1 transaction.

(48) **Option 1 Outages: Status Response (T3)**

This transaction set:

From a TDSP to CR, is used to provide status information for a previously submitted T0, Option 1 Outages: Outage Status Request, message. This is a required transaction for the TDSP when an Option 1 CR utilizes the T0 transaction.

(49) **Option 1 Outages: Trouble Completion Report (T4)**

This transaction set:

From a TDSP to CR, is used by the TDSP to notify the CR that the trouble condition has been resolved. This is a required transaction for the TDSP when an Option 1 CR utilizes the T1, Option 1 Outages: Trouble Reporting Request, transaction.

ERCOT Nodal Protocols

Section 23

Form B: Load Serving Entity (LSE) Application for Registration

~~May 1, 2024~~TBD

Date Received: ______________________

LOAD SERVING ENTITY (LSE)
APPLICATION FOR REGISTRATION

This application is for approval as a Load Serving Entity (LSE) by the Electric Reliability Council of Texas Inc. (ERCOT) in accordance with the ERCOT Protocols. Information may be inserted electronically to expand the reply spaces as necessary. ERCOT will accept the completed, executed application via email to MPRegistration@ercot.com (.pdf version). In addition to the application, ERCOT must receive an application fee in the amount of $500 via Electronic Funds Transfer (EFT) (wire or Automated Clearing House (ACH)), if the applicant is a Retail Electric Provider (REP) and/or Competitive Retailer (CR), per Section 9.16.2, User Fees. All payments should reference the applicant's name and Data Universal Numbering System (DUNS) Number (DUNS #) in the remarks. If you need assistance filling out this form, or if you have any questions, please call (512) 248-3900.

This application and all subsequent documents provided to ERCOT must be signed by the Authorized Representative, Backup Authorized Representative or an Officer of the company listed herein, as appropriate. ERCOT may request additional information as reasonably necessary to support operations under the ERCOT Protocols.

PART I – ENTITY INFORMATION

Legal Name of the Applicant:	
Legal Address of the Applicant:	Street Address:
	City, State, Zip:
DUNS[1] Number:	

[1]Defined in Section 2.1, Definitions.

1. Authorized Representative ("AR"). Defined in Section 2.1, Definitions.

Name:	
Telephone:	
Email Address:	

2. Backup AR. *(Optional)* This person may sign any form for which an AR's signature is required and will perform the functions of the AR in the event the AR is unavailable.

Name:	
Telephone:	
Email Address:	

3. Type of Legal Structure. (Please indicate only one.)

☐ Individual ☐ Partnership ☐ Municipally Owned Utility

☐ Electric Cooperative ☐ Limited Liability Company ☐ Corporation
☐ Other: _____

If Applicant is not an individual, provide the state in which the Applicant is organized, _____, and the date of organization: _____

4. User Security Administrator (USA). As defined in Section 16.12, User Security Administrator and Digital Certificates, the USA is responsible for managing the Market Participant's access to ERCOT's computer systems through Digital Certificates.

Name:	
Telephone:	
Email Address:	

4a. ☐ By checking this box, Applicant hereby requests that ERCOT evaluate Applicant's eligibility to opt out of the requirement that Market Participant designate a USA and receive Digital Certificates, and affirms the following:

(a) Applicant is applying to register with ERCOT as either a Municipally Owned Utility (MOU) or an Electric Cooperative (EC), and as a Distribution Service Provider (DSP) and/or Load Serving Entity (LSE).

(b) Applicant is not, and will not, be designated as a Transmission Operator with ERCOT.

(c) Applicant understands that by opting out, it will not be granted access to portions of the ERCOT Market Information System (MIS) that require Digital Certificate access.

(d) Applicant understands that it can cancel any approved opt-out request, designate a USA, and begin receiving Digital Certificates by properly completing Section 23, Form E, Notice of Change of Information, and meeting the requirements under Section 16.12, User Security Administrator and Digital Certificates.

(e) If determined ineligible, Applicant must designate a USA, receive Digital Certificates and comply with requirements under Section 16.12.

5. Backup USA. *(Optional)* This person may perform the functions of the USA in the event the Primary USA is unavailable.

Name:	
Telephone:	
Email Address:	

6. Cybersecurity. This contact is responsible for communicating Cybersecurity Incidents.

Name:	
Telephone:	
Email Address:	

7. Transition/Acquisition ("TA"). Requirement for Competitive Retailers (CRs). Responsible for coordinating Mass TA events between ERCOT, Transmission and/or Distribution Service Providers (TDSPs) and CRs. The CR may be a Provider of Last Resort (POLR), designated CR, ~~gaining~~ Gaining CR or ~~losing~~ Losing CR. Includes TA Business ("TAB"), TA Regulatory ("TAR") and TA Technical ("TAT").

TAB:

Name:	
Telephone:	
Email Address:	

TAR:

Name:	
Telephone:	
Email Address:	

TAT:

Name:	
Telephone:	
Email Address:	

8. Type of Applicant. Please indicate how the Applicant intends to operate in the market pursuant to the ERCOT Protocols. Please check all that apply.

☐ **CR** – MOU or an EC that offers Customer Choice and sells electric energy at retail in the restructured electric power market in Texas; or a Retail Electric Provider (REP) as defined in P.U.C. SUBST. R. 25.5, Definitions. (If CR, check one of the following):

- ☐ **Opt-In MOU or EC** – A MOU or an EC that offers Customer Choice.
- ☐ **REP** – A person that sells electric energy to retail Customers in this state. As provided in the Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 31.002(17) (Vernon 1998 & Supp. 2007) (PURA), a REP may not own or operate generation assets. As provided in PURA § 39.353(b), a REP is not an Aggregator.

☐ **Non-Opt-In Entity (NOIE)** – An EC or MOU that does not offer Customer Choice and does not plan to operate as a CR.

☐ **External LSE (ELSE)** – A distribution service provider (as that term is defined in P.U.C. SUBST. R. 25.5), which includes an electric utility, a MOU, or an EC that has a legal duty to serve one or more Customers connected to the ERCOT System but that does not own or operate Facilities connecting Customers to the ERCOT System.

9. Default method for receiving transaction information from Transaction Clearinghouse.

Select one: ☐ EDI, ☐ XML, or ☐ Portal

PART II – SCHEDULING INFORMATION

1. Designation of a Qualified Scheduling Entity (QSE). Provide all information requested in Attachment A and have the document executed by both parties.

PART III – REP INFORMATION

(Part III applies to REPs only.)

1. Other Trade or Commercial Names on PUCT Certificate. (Limit: 4)

Other Trade/Commercial Name:	DUNS Number:

2. Texas Office. Supply the Texas office location information indicated below prior to providing retail electric service in Texas:

Name in use at Texas office:	
Street Address of Texas office:	
City, State, Zip:	
Telephone:	
Email:	

3. Service Area. Please designate service area by selecting one of the options below.

☐ **Option 1** – For LSEs defining service area by geography. Check only one of the following boxes and complete supplemental information, if any, to designate desired geographical service area:

☐ The geographic area of the entire state of Texas.

☐ A specific geographic area (including the zip codes applicable to that area), as follows (list them): _____.

☐ The service area of specific transmission and distribution utilities and/or Municipally Owned Utilities (MOUs) or Electric Cooperatives (ECs) in which competition is offered, as follows (list them): _____.

☐ The geographic area of ERCOT or other independent organization to the extent it is within Texas, as follows (name it): _____

☐ **Option 2** – For LSEs defining service area by customers. Provide an attached list of each individual retail customer, by name, with who it has contracted to provide one megawatt (1 MW) or more of capacity, pursuant to subsection (d)(2)(A) of P.U.C. SUBST. R. 25.107, Certification of Retail Electric Providers (REPs).

☐ **Option 3** – For LSEs that sell electricity exclusively to a retail customer other than a small commercial consumer and residential customer from a Distributed Generation (DG) facility located on a site controlled by that customer.

4. PUCT Certification.

Date Certificate granted:	Certificate Number:

PART IV – ADDITIONAL REQUIRED INFORMATION

1. Officers. ERCOT will obtain the names of all individuals and/or entities listed with the Texas Secretary of State or otherwise designated as having binding authority for the Applicant. ERCOT will use this list of individuals to determine who can execute such documents as the Standard Form Market Participant Agreement (Section 22, Attachment A), Amendment to Standard Form Market Participant Agreement (Section 22, Attachment C), Digital Certificate Audit Attestation (DCAA), etc. Alternatively, additional documentation (Articles of Incorporation, Board Resolutions, Delegation of Authority, Secretary's Certificate, etc.) can be provided to prove binding authority for the Applicant.

2. Affiliates and Other Registrations. Provide the name, legal structure, and relationship of each of the Applicant's affiliates, if applicable. See Section 2.1, Definitions, for the definition of "Affiliate." Please also provide the name and type of any other ERCOT Market Participant registrations held by the Applicant. *(Attach additional pages if necessary.)*

Affiliate Name (or name used for other ERCOT registration)	**Type of Legal Structure** (partnership, limited liability company, corporation, etc.)	**Relationship** (parent, subsidiary, partner, affiliate, etc.)

PART V – SIGNATURE

I affirm that I have personal knowledge of the facts stated in this application and that I have the authority to submit this application form on behalf of the Applicant. I further affirm that all statements made and information provided in this application form are true, correct and complete, and that the Applicant will provide to ERCOT any changes in such information in a timely manner.

Signature of AR, Backup AR or Officer:	
Printed Name of AR, Backup AR or Officer:	
Date:	

Attachment A – QSE Acknowledgment

Acknowledgment by Designated QSE for Scheduling and Settlement Responsibilities with ERCOT

The Applicant below has named the QSE listed below as its designated QSE to represent the Applicant for scheduling and Settlement transactions with ERCOT.

The Applicant's designated QSE, listed below, hereby acknowledges that it does represent the Applicant and that it shall be responsible for the Applicant's scheduling and Settlement transactions with ERCOT pursuant to the ERCOT Protocols.

The requested effective date for such representation is: _____**

or

Establish partnership at the earliest possible date ☐

Acknowledgment by **QSE**:

Signature of AR for QSE:	
Printed Name of AR:	
Email Address of AR:	
Date:	
Name of Designated QSE:	
DUNS of Designated QSE:	

Acknowledgment by **Applicant**:

Signature of AR for MP:	
Printed Name of AR:	
Email Address of AR:	
Date:	
Name of MP:	
DUNS No. of MP:	

** *Actual effective date will depend on time needed to implement the relationship in ERCOT systems once ERCOT has received all necessary information (a minimum of three Business Days), and may be later than the requested effective date. ERCOT will notify the parties of the actual effective date.*

ERCOT Impact Analysis Report

NPRR Number	<u>1227</u>	NPRR Title	Related to RMGRR181, Alignment of Defined Term Usage and Resolution of Inconsistencies
Impact Analysis Date	April 30, 2024		
Estimated Cost/Budgetary Impact	None.		
Estimated Time Requirements	No project required. This Nodal Protocol Revision Request (NPRR) can take effect upon implementation of Retail Market Guide Revision Request (RMGRR) 181, Alignment of Defined Term Usage and Resolution of Inconsistencies. See Comments		
ERCOT Staffing Impacts (across all areas)	Ongoing Requirements: No impacts to ERCOT staffing.		
ERCOT Computer System Impacts	No impacts to ERCOT computer systems.		
ERCOT Business Function Impacts	No impacts to ERCOT business functions.		
Grid Operations & Practices Impacts	No impacts to ERCOT grid operations and practices.		

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

Comments
There are no additional impacts to this NPRR beyond what was captured in the Impact Analysis for RMGRR181.

Board Report

NPRR Number	**1236**	**NPRR Title**	**RTC+B Modifications to RUC Capacity Short Calculations**
Date of Decision	October 10, 2024		
Action	Recommended Approval		
Timeline	Normal		
Estimated Impacts	Cost/Budgetary: None Project Duration: No project required		
Proposed Effective Date	Upon system implementation of PR447, Real-Time Co-Optimization (RTC)		
Priority and Rank Assigned	Not applicable		
Nodal Protocol Sections Requiring Revision	5.7.4.1.1, Capacity Shortfall Ratio Share		
Related Documents Requiring Revision/Related Revision Requests	None		
Revision Description	This Nodal Protocol Revision Request (NPRR) reflects the modifications addressed in the Real-Time Co-optimization Plus Batteries (RTC+B) Task Force whitepaper to the Reliability Unit Commitment (RUC) Capacity Short calculations. These modifications were discussed in RTC+B Task Force meetings on February 21, March 19, and April 10, 2024 as part of RTC+B Task Force Issue No. 17 and were endorsed by TAC on April 15, 2024. This NPRR addresses limitations in the current RUC Capacity Short calculations by considering Ancillary Service sub-types and changes to the calculation process involving Regulation Down Service (Reg-Down). This NPRR also addresses changes required to align Protocol language with the recently-approved NPRR1204, Considerations of State of Charge with Real-Time Co-Optimization Implementation, as it relates to the RUC process. This NPRR implements an approach that continues the current policy (i.e., allocating costs in a manner consistent with cost causation) to first proportionally assign RUC Make Whole costs to Qualified Scheduling Entities (QSEs) that are determined to be short		

	of capacity or Ancillary Service capability when the RUC decision was made and, if necessary, assign the remaining RUC Make Whole costs to QSEs based on Load Ratio Share (LRS). This NPRR continues to follow the TAC-approved RTCTF Key Principle No. 3 (12).
Reason for Revision	☐ Strategic Plan Objective 1 – Be an industry leader for grid reliability and resilience ☐ Strategic Plan Objective 2 - Enhance the ERCOT region's economic competitiveness with respect to trends in wholesale power rates and retail electricity prices to consumers ☐ Strategic Plan Objective 3 - Advance ERCOT, Inc. as an independent leading industry expert and an employer of choice by fostering innovation, investing in our people, and emphasizing the importance of our mission ☒ General system and/or process improvement(s) ☐ Regulatory requirements ☐ ERCOT Board/PUCT Directive *(please select ONLY ONE – if more than one apply, please select the ONE that is most relevant)*
Justification of Reason for Revision and Market Impacts	After the RTC+B initiative was restarted, the NPRRs approved while the project was on hold (e.g., NPRR1093, Load Resource Participation in Non-Spinning Reserve) were analyzed to determine if there were any gaps or impacts to the RTC+B initiative that needed to be addressed. In this process the following items were identified for the RUC Capacity Short calculation: 1. Certain issues in the approved RTC+B Protocols: a. Ancillary Service sub-types are not currently considered. For example, a QSE with an RRS-PFR position can cover it with RRS-UFR or RRS-FFR, which should not be allowed. b. The logic for Reg-Down has a deficiency in which it is possible for the same Resource capacity to be used for Reg-Down as well as any other Up Ancillary Service types/sub-types (Reg-Up, RRS-FFR, RRS-UFR, RRS-PFR, ECRSS, or Non-Spin), which should not be permissible. c. The logic is included to account for an Energy Storage Resource (ESR) providing Ancillary Service when charging.

	d. An ASONPOSSNAP and ASONPOSADJ formula correction is necessary as well as related edits to the billing determinants ASOFFOFRSNAP and ASOFFOFRADJ. 2. The need to incorporate ESR State of Charge (SOC) considerations based on NPRR 1204 and associated discussions with stakeholders in 2023.
PRS Decision	On 7/18/24, PRS voted unanimously to recommend approval of NPRR1236 as revised by PRS. All Market Segments participated in the vote. On 8/8/24, PRS voted unanimously to endorse and forward to TAC the 7/18/24 PRS Report and 6/4/24 Impact Analysis for NPRR1236. All Market Segments participated in the vote.
Summary of PRS Discussion	On 7/18/24, ERCOT Staff provided an overview of NPRR1236 and proposed desktop edits to clarify the definition of a Settlement variable and correct a typographical error. On 8/8/24, participants reviewed the 6/4/24 Impact Analysis for NPRR1236.
TAC Decision	On 8/28/24, TAC voted unanimously to recommend approval of NPRR1236 as recommended by PRS in the 8/8/24 PRS Report. All Market Segments participated in the vote.
Summary of TAC Discussion	On 8/28/24, there was no additional discussion beyond TAC review of the items below.
TAC Review/Justification of Recommendation	[X] Revision Request ties to Reason for Revision as explained in Justification [X] Impact Analysis reviewed and impacts are justified as explained in Justification [X] Opinions were reviewed and discussed [X] Comments were reviewed and discussed (if applicable) [ ] Other: (explain)
ERCOT Board Decision	On 10/10/24, the ERCOT Board voted unanimously to recommend approval of NPRR1236 as recommended by TAC in the 8/28/24 TAC Report.

Opinions

Board Report

Credit Review	ERCOT Credit Staff and the Credit Finance Sub Group (CFSG) have reviewed NPRR1236 and do not believe that it requires changes to credit monitoring activity or the calculation of liability.
Independent Market Monitor Opinion	IMM has no opinion on NPRR1236.
ERCOT Opinion	ERCOT supports approval of NPRR1236.
ERCOT Market Impact Statement	ERCOT Staff has reviewed NPRR1236 and believes the market impact for NPRR1236 addresses limitations in the current RTC grey-boxed language for RUC Capacity Short calculations by considering Ancillary Service sub-types, changes to the calculation process involving Reg-Down, correction to bill determinant formulas, and SOC of ESRs in alignment with NPRR1204. The changes in this NPRR were anticipated by the RTC+B project and are already being incorporated in the design.

Sponsor	
Name	Dave Maggio
E-mail Address	david.maggio@ercot.com
Company	ERCOT
Phone Number	512-248-6998
Cell Number	
Market Segment	Not applicable

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

Comments Received	
Comment Author	**Comment Summary**
None	

Market Rules Notes

Board Report

Please note the baseline Protocol language in the Section 5.7.4.1.1 has been updated to reflect the incorporation of the following NPRRs into the Protocols:

- NPRR1139, Adjustments to Capacity Shortfall Ratio Share for IRRs (unboxed 6/28/24)

Proposed Protocol Language Revision

5.7.4.1.1 Capacity Shortfall Ratio Share

(1) In calculating the amount short for each QSE, the available capacity of an IRR when determining responsibility for the corresponding RUC charges shall be the lessor of the HSL value as reflected in the COP and the Wind-powered Generation Resource Production Potential (WGRPP), as described in Section 4.2.2, Wind-Powered Generation Resource Production Potential, for a Wind-powered Generation Resource (WGR), or the PhotoVoltaic Generation Resource Production Potential (PVGRPP), as described in Section 4.2.3, PhotoVoltaic Generation Resource Production Potential, for a PhotoVoltaic Generation Resource (PVGR), at the time of RUC execution. For an IRR, the HASLSNAP variable used below shall be equal to the minimum of the WGRPP or PVGRPP described above and the HSL value as reflected in the QSE's COP, at the time of the RUC execution.

(2) In calculating the amount short for each QSE, the QSE must be given a capacity credit for non-Intermittent Renewable Resources (IRRs) that were given notice of decommitment within the two hours before the Operating Hour as a result of the RUC process by setting the HASLSNAP and HASLADJ variables used below equal to the HASLSNAP value for the Resource immediately before the decommitment instruction was given.

(3) In calculating the short amount for each QSE, if the High Ancillary Service Limit (HASL) for a Resource was credited to the QSE during the RUC snapshot but the Resource experiences a Forced Outage within two hours before the start of the Settlement Interval, then the HASL for that Resource is also credited to the QSE in the HASLADJ.

(4) In calculating the short amount for each QSE, if the DCIMPSNAP was credited to the QSE during the RUC snapshot but the entire Direct Current Tie (DC Tie) experiences a Forced Outage within two hours before the start of the Settlement Interval, then the DCIMPSNAP is also credited to the QSE in the DCIMPADJ.

(5) For Combined Cycle Generation Resources, if more than one Combined Cycle Generation Resource is shown On-Line in its COP for the same Settlement hour, then the provisions of paragraph (6)(a) of Section 3.9.1, Current Operating Plan (COP) Criteria, apply in the determination of the On-Line Combined Cycle Generation Resource for that Settlement hour.

(6) The capacity shortfall ratio share of a specific QSE for a particular RUC process is calculated, for a 15-minute Settlement Interval, as follows:

$$\textbf{RUCSFRS}_{\,ruc,\,i,\,q} = \textbf{RUCSF}_{\,ruc,\,i,\,q} \,/\, \textbf{RUCSFTOT}_{\,ruc,\,i}$$

Where:

$$\textbf{RUCSFTOT}_{\,ruc,\,i} = \sum_{q} \textbf{RUCSF}_{\,ruc,\,i,\,q}$$

(7) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval is:

$$\textbf{RUCSF}_{\,ruc,\,i,\,q} = \textbf{Max (0, Max (RUCSFSNAP}_{\,ruc,\,q,\,i}\textbf{, RUCSFADJ}_{\,ruc,\,q,\,i}\textbf{)} - \sum_{z\ is\ prior\ to\,ruc} \textbf{RUCCAPCREDIT}_{\,q,\,i,\,z}\textbf{)}$$

(8) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval, as measured at the snapshot, is:

$$\textbf{RUCSFSNAP}_{\,ruc\,,q\,,i} = \textbf{Max (0, ((}\sum_{p}\textbf{RTAML}_{\,q,\,p,\,i}\textbf{ * 4)} - \textbf{RUCCAPSNAP}_{\,ruc,\,q,\,i}\textbf{))}$$

(9) The amount of capacity that a QSE had according to the RUC snapshot for a 15-minute Settlement Interval is:

$$\textbf{RUCCAPSNAP}_{\,ruc,\,q,\,i} = \sum_{r}\textbf{HASLSNAP}_{\,q,\,r,\,h} + \textbf{(RUCCPSNAP}_{\,q,\,h} - \textbf{RUCCSSNAP}_{\,q,\,h}\textbf{)} + \textbf{(}\sum_{p}\textbf{DAEP}_{\,q,\,p,\,h} - \sum_{p}\textbf{DAES}_{\,q,\,p,\,h}\textbf{)} + \textbf{(}\sum_{p}\textbf{RTQQEPSNAP}_{\,q,\,p,\,i} - \sum_{p}\textbf{RTQQESSNAP}_{\,q,\,p,\,i}\textbf{)} + \sum_{p}\textbf{DCIMPSNAP}_{\,q,\,p,\,i}$$

(10) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval, as measured at Real-Time, but including capacity from IRRs as seen in the RUC snapshot, is:

$$\textbf{RUCSFADJ}_{\,ruc,\,q,\,i} = \textbf{Max (0, ((}\sum_{p}\textbf{RTAML}_{\,q,\,p,\,i}\textbf{) *4)} - \textbf{(}\sum_{r=IRRsOnly}\textbf{HASLSNAP}_{\,ruc,\,q,\,r,\,h} + \textbf{RUCCAPADJ}_{\,q,\,i}\textbf{))}$$

(11) The amount of capacity that a QSE had in Real-Time for a 15-minute Settlement Interval, excluding capacity from IRRs, is:

$$\textbf{RUCCAPADJ}_{\,q,\,i} = \sum_{r}\textbf{HASLADJ}_{\,q,\,r,\,h} + \textbf{(RUCCPADJ}_{\,q,\,h} - \textbf{RUCCSADJ}_{\,q,\,h}\textbf{)} + \textbf{(}\sum_{p}\textbf{DAEP}_{\,q,\,p,\,h} - \sum_{p}\textbf{DAES}_{\,q,\,p,\,h}\textbf{)} + \textbf{(}\sum_{p}\textbf{RTQQEPADJ}_{\,q,\,p,\,i} - \sum_{p}\textbf{RTQQESADJ}_{\,q,\,p,\,i}\textbf{)} + \sum_{p}\textbf{DCIMPADJ}_{\,q,\,p,\,i}$$

The above variables are defined as follows:

Variable	Unit	Definition
$RUCSFRS_{ruc, i, q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE *q*'s capacity shortfall to the sum of all QSEs' capacity shortfalls, for the RUC process *ruc*, for the 15-minute Settlement Interval *i*.
$RUCSF_{ruc, i, q}$	MW	*RUC Shortfall*—The QSE *q*'s capacity shortfall for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
$RUCSFTOT_{ruc, i}$	MW	*RUC Shortfall Total*—The sum of all QSEs' capacity shortfalls, for a RUC process *ruc*, for a 15-minute Settlement Interval *i*.
$RUCSFSNAP_{ruc, q, i}$	MW	*RUC Shortfall at Snapshot*—The QSE *q*'s capacity shortfall according to the snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
$RUCSFADJ_{ruc, q, i}$	MW	*RUC Shortfall at Adjustment Period*—The QSE *q*'s Adjustment Period capacity shortfall, including capacity from IRRs as seen in the snapshot for the RUC process *ruc*, for the 15-minute Settlement Interval *i*.
$RUCCAPCREDIT_{q, i, z}$	MW	*RUC Capacity Credit by QSE*—The QSE *q*'s capacity credit resulting from capacity paid through the RUC Capacity-Short Amount for RUC process *z* for the 15-minute Settlement Interval *i*.
$RTAML_{q, p, i}$	MWh	*Real-Time Adjusted Metered Load*—The QSE *q*'s Adjusted Metered Load (AML) at the Settlement Point *p* for the 15-minute Settlement Interval *i*.
$RUCCAPSNAP_{ruc, q, i}$	MW	*RUC Capacity Snapshot at time of RUC*—The amount of the QSE *q*'s calculated capacity in the COP and Trades Snapshot for the RUC process *ruc* for a 15-minute Settlement Interval *i*.
$HASLSNAP_{q, r, h}$	MW	*High Ancillary Services Limit at Snapshot*—The HASL of the Resource *r* represented by the QSE *q*, according to the COP and Trades Snapshot for the RUC process for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.
$DCIMPADJ_{q, p, i}$	MW	*DC Import per QSE per Settlement Point*—The approved aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p* according to the Adjustment Period snapshot, for the 15-minute Settlement Interval *i*.
$DCIMPSNAP_{q, p, i}$	MW	*DC Import per QSE per Settlement Point*—The approved aggregated DC Tie Schedule submitted by QSE *q* as an importer into the ERCOT System through DC Tie *p*, according to the snapshot for the RUC process for the hour that includes the 15-minute Settlement Interval *i*.
$RUCCPSNAP_{q, h}$	MW	*RUC Capacity Purchase at Snapshot*—The QSE *q*'s capacity purchase, according to the COP and Trades Snapshot for the RUC process for the hour *h* that includes the 15-minute Settlement Interval.
$RUCCSSNAP_{q, h}$	MW	*RUC Capacity Sale at Snapshot*—The QSE *q*'s capacity sale, according to the COP and Trades Snapshot for the RUC process for the hour *h* that includes the 15-minute Settlement Interval.
$RUCCAPADJ_{q, i}$	MW	*RUC Capacity Snapshot during Adjustment Period*—The amount of the QSE *q*'s calculated capacity in the RUC according to the COP and Trades Snapshot, excluding capacity for IRRs, at the end of the Adjustment Period for a 15-minute Settlement Interval *i*.
$HASLADJ_{q, r, h}$	MW	*High Ancillary Services Limit at Adjustment Period*—The HASL of a non-IRR *r* represented by the QSE *q*, according to the Adjustment Period snapshot, for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train.

Variable	Unit	Definition
RUCCPADJ $_{q,\ h}$	MW	*RUC Capacity Purchase at Adjustment Period*—The QSE *q*'s capacity purchase, according to the Adjustment Period COP and Trades Snapshot for the hour *h* that includes the 15-minute Settlement Interval.
RUCCSADJ $_{q,\ h}$	MW	*RUC Capacity Sale at Adjustment Period*—The QSE *q*'s capacity sale, according to the Adjustment Period COP and Trades Snapshot for the hour *h* that includes the 15-minute Settlement Interval.
DAEP $_{q,\ p,\ h}$	MW	*Day-Ahead Energy Purchase*—The QSE *q*'s energy purchased in the DAM at the Settlement Point *p* for the hour *h* that includes the 15-minute Settlement Interval.
DAES $_{q,\ p,\ h}$	MW	*Day-Ahead Energy Sale*—The QSE *q*'s energy sold in the DAM at the Settlement Point *p* for the hour *h* that includes the 15-minute Settlement Interval.
RTQQEPSNAP $_{q,\ p,\ i}$	MW	*QSE-to-QSE Energy Purchase by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the COP and Trades Snapshot.
RTQQESSNAP $_{q,\ p,\ i}$	MW	*QSE-to-QSE Energy Sale by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the COP and Trades Snapshot.
RTQQEPADJ $_{q,\ p,\ i}$	MW	*QSE-to-QSE Energy Purchase by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the buyer at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the last COP and Trades Snapshot at the end of the Adjustment Period for that Settlement Interval.
RTQQESADJ $_{q,\ p,\ i}$	MW	*QSE-to-QSE Energy Sale by QSE by point*—The QSE *q*'s Energy Trades in which the QSE is the seller at the delivery Settlement Point *p* for the 15-minute Settlement Interval *i*, in the last COP and Trades Snapshot at the end of the Adjustment Period for that Settlement Interval.
q	none	A QSE.
p	none	A Settlement Point.
r	none	A Generation Resource that is QSE-committed or planning to operate as a Quick Start Generation Resource (QSGR) for the Settlement Interval as shown by the Resource Status of OFFQS in the COP and Trades Snapshot and/or Adjustment Period snapshot; or RUC-decommitted for the Settlement Interval (subject to paragraphs (1) and (2) above); or a Switchable Generation Resource (SWGR) released by a non-ERCOT Control Area Operator (CAO) to operate in the ERCOT Control Area due to an ERCOT RUC instruction for an actual or anticipated EEA condition. If the Settlement Interval is a RUCAC-Interval, *r* represents the Combined Cycle Generation Resource that was QSE-committed at the time the RUCAC was issued.
z	none	A previous RUC process for the Operating Day.
i	none	A 15-minute Settlement Interval.
h	none	The hour that includes the Settlement Interval *i*.
ruc	none	The RUC process for which this RUC Shortfall Ratio Share is calculated.

[NPRR1009, NPRR1014, NPRR1029, and NPRR1032: Replace applicable portions of Section 5.7.4.1.1 above with the following upon system implementation of the Real-Time Co-

Optimization (RTC) project for NPRR1009; or upon system implementation for NPRR1014, NPRR1029, or NPRR1032:]

5.7.4.1.1 Capacity Shortfall Ratio Share

(1) In calculating the shortfall amount for each QSE, the Resource capacity (RCAPSNAP and RCAPADJ) shall be calculated for a Generation Resource ~~or ESR~~ that meets any of the following conditions:

(a) QSE-committed;

(b) Planning to operate as a Quick Start Generation Resource (QSGR) for the Settlement Interval as shown by the COP Status of OFFQS in the RUC Snapshot for the RUC Process and/or Adjustment Period; or

(c) A Switchable Generation Resource (SWGR) that is released by a non-ERCOT Control Area Operator (CAO) to operate in the ERCOT Control Area due to an ERCOT RUC instruction for an actual or anticipated EEA condition and that is shown as On-Line in its COP; or

(d) If the Settlement Interval is a RUCAC-Interval, the Combined Cycle Generation Resource that was QSE-committed at the time the RUCAC was issued, excluding the condition for SWGRs as describe in paragraph (c) above.

(2) In calculating the amount short for each QSE, the available capacity of an IRR when determining responsibility for the corresponding RUC charges shall be the lesse~~o~~r of the HSL value, as reflected in the COP, and the Wind-powered Generation Resource Production Potential (WGRPP), as described in Section 4.2.2, Wind-Powered Generation Resource Production Potential, for a Wind-powered Generation Resource (WGR), or the PhotoVoltaic Generation Resource Production Potential (PVGRPP), as described in Section 4.2.3, PhotoVoltaic Generation Resource Production Potential, for a PhotoVoltaic Generation Resource (PVGR), at the time of RUC execution. For an IRR, the RCAPSNAP variable used below shall be equal to the minimum of the WGRPP or PVGRPP described above and the HSL value as reflected in the QSE's COP, at the time of the RUC execution.

(3) In calculating the amount short for each QSE, the QSE must be given a capacity credit for non-Intermittent Renewable Resources (IRRs) that were given notice of decommitment within the two hours before the Operating Hour as a result of the RUC process by setting the RCAPSNAP and RCAPADJ variables used below set equal to the RCAPSNAP value for the Resource immediately before the decommitment instruction was given.

(4) In calculating the short amount for each QSE, if the RCAPSNAP for a non-IRR was credited to the QSE during the RUC Snapshot but the Resource experiences a Forced

Outage within two hours before the start of the Settlement Interval, then the RCAPSNAP for that Resource is also credited to the QSE in the RCAPADJ.

(5) In calculating the short amount for each QSE, if the DCIMPSNAP was credited to the QSE during the RUC Snapshot but the entire Direct Current Tie (DC Tie) experiences a Forced Outage within two hours before the start of the Settlement Interval, then the DCIMPSNAP is also credited to the QSE in the RTDCIMP.

(6) For Combined Cycle Generation Resources, if more than one Combined Cycle Generation Resource is shown On-Line in its COP for the same Settlement hour, then the provisions of paragraph (6)(a) of Section 3.9.1, Current Operating Plan (COP) Criteria, apply in the determination of the On-Line Combined Cycle Generation Resource for that Settlement hour.

(7) The QSE Ancillary Service shortfall calculation in MW for each hour in the RUC Snapshot or for the end of the Adjustment Period involves solving an optimization that minimizes any potential Ancillary Service shortfall for a QSE. This is done by determining the optimal utilization of Ancillary Service capabilities within each QSE's portfolio of Resources to meet its net Ancillary Service position for each Ancillary Service sub-type. A QSE's Ancillary Service shortfall for an hour is the difference between the QSE's net Ancillary Service position and its coverage of Ancillary Services using the outputs of this optimization based on the QSE's Resource Ancillary Service capabilities for that hour as reflected in the COPs submitted by the QSE.

(a) For each Ancillary Service sub-type, the Ancillary Service MW capability for each Resource in the QSE's portfolio for a given hour in the RUC Snapshot or at the end of the Adjustment Period (ASMWCAPSNAP and ASMWCAPADJ) is calculated as the minimum of:

(i) HSL minus LSL in the COP if the Resource is On-Line (ON, ONOS, ONSC, and ONL). If a Generation Resource COP Resource Status is OFF or OFFQS, only the COP HSL is used. For a Combined Cycle Train, the Resource refers to a particular Combined Cycle Generation Resource belonging to that Combined Cycle Train. For a Combined Cycle Train, select the Combined Cycle Generation Resource that is On-Line (ON or ONOS) with the highest HSL. If none of the Combined Cycle Generation Resources of a Combined Cycle Train are On-Line, then select the Combined Cycle Generation Resource that has the highest HSL and a COP Resource Status of OFF and that can be started up within 30 minutes;

(ii) Submitted Ancillary Service Offer MW quantity for the Ancillary Service type/sub-type;

(iii) Submitted COP Ancillary Service MW capability; and

(iv) Qualified Ancillary Service MW amount for the Ancillary Service sub-type. For Resources with COP Resource Status of OFFQS, the qualified MW amounts for Reg-Up, Reg-Down, and RRS will be set to zero. For Resources with a COP Resource Status of OFF, the qualified MW amounts for Reg-Up, Reg-Down, RRS, and ECRS will be set to zero.

(b) The QSE Ancillary Service shortfall calculation enforces the following constraints for each hour using data from the RUC Snapshot or the end of the Adjustment Period:

(i) Ensure that a QSE's portfolio of Resource capacities are only used to cover that QSE's net Ancillary Service position by each Ancillary Service sub-type.

(ii) A QSE's Fast Frequency Response Service (FFRS) position can be covered by the QSE's portfolio of Energy Storage Resources (ESRs) qualified to provide FFRS, Load Resources having a high-set under-frequency Relay that are qualified for Responsive Reserve (RRS) or Controllable Load Resources, Generation Resources, and ESRs that are qualified to provide RRS as Primary Frequency Response.

(iii) A QSE's RRS position of the type provided by Load Resources having a high-set under-frequency Relay that are qualified for RRS can be covered by the QSE's portfolio of Load Resources qualified to provide this type of RRS or Controllable Load Resources, Generation Resources, and ESRs that are qualified to provide RRS as Primary Frequency Response.

(iv) A QSE's ERCOT Contingency Reserve Service (ECRS) position of the type that is not SCED-dispatchable can be covered by the QSE's portfolio of Load Resources that are qualified to provide non-SCED dispatchable ECRS, or by Controllable Load Resources, Generation Resources, and ESRs that are qualified to provide ECRS of the type that is SCED-dispatchable.

(v) A QSE's Non-Spinning Reserve (Non-Spin) position of the type that is not SCED-dispatchable can be covered by the QSE's portfolios of Load Resources that are qualified to provide non-SCED dispatchable Non-Spin, or by Controllable Load Resources, Generation Resources, and ESRs that are qualified to provide Non-Spin of the type that is SCED-dispatchable.

(vi) For each Resource and Ancillary Service sub-type:

(A) Ancillary Service capacity used for each Ancillary Service sub-type cannot exceed that Resource's Ancillary Service capability for that Ancillary Service sub-type.

(B) The sum of all the Ancillary Service capacities used for each Ancillary Service sub-type cannot exceed the COP HSL minus LSL limits. For Generation Resources that have a Resource Status of OFF and the Ancillary Service type is Non-Spin, consider LSL to be zero. Likewise, for Generation Resources that have a Resource Status of OFFQS and the Ancillary Service type is Non-Spin or ECRS, consider LSL to be zero.

(C) For ESRs, consider:

(1) Duration requirements for each Ancillary Service type and the submitted COP values for Hour Beginning Planned State of Charge (SOC), Minimum SOC (MinSOC) and Maximum SOC (MaxSOC);

(2) Ancillary Service deployment factors, duration requirements for different Ancillary Service types or sub-types, and the difference between the submitted COP Hour Beginning Planned SOC for the hour under consideration and the next hour; and

(3) The charge or discharge MW required to satisfy the above constraints.

(c) The outputs of the optimization for each Resource are:

(i) The Resource's MW capacity used to cover its QSE's net Ancillary Service position by Ancillary Service sub-type for a given hour. These values are ASMWCAPUSNAP for a given hour in the RUC Snapshot and ASMWCAPUADJ for the end of the Adjustment Period.

(ii) For an ESR, the MW discharge (positive) or charge (negative) required to support the ESR's calculated Ancillary Service coverage of its QSE's net Ancillary Service position, considering the submitted COP values for MinSOC, MaxSOC, and the difference in the Hour Beginning Planned SOC for the hour under consideration and the next hour. This value will also account for Ancillary Service deployment factors and the duration requirements for energy and different Ancillary Service types. These values are MWSNAP for a given hour in the RUC Snapshot and MWADJ for the end of the Adjustment Period.

(8~~7~~) The capacity shortfall ratio share of a specific QSE for a particular RUC process is calculated, for a 15-minute Settlement Interval, as follows:

$$\mathbf{RUCSFRS}_{\,ruc,\,i,\,q} = \mathbf{RUCSF}_{\,ruc,\,i,\,q} \,/\, \mathbf{RUCSFTOT}_{\,ruc,\,i}$$

Where:

$$\text{RUCSFTOT}_{\,ruc,\,i} = \sum_{q} \text{RUCSF}_{\,ruc,\,i,\,q}$$

(~~8~~9) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval is:

$$\mathbf{RUCSF}_{\,ruc,\,i,\,q} = \mathbf{Max\ (0,\ Max\ (RUCSFSNAP}_{\,ruc,\,q,\,i}\mathbf{,\ RUCSFADJ}_{\,ruc,\,q,\,i}\mathbf{)} - \sum_{z\text{ is prior to }ruc} \mathbf{RUCCAPCREDIT}_{\,q,\,i,\,z}\mathbf{)}$$

(~~9~~10) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval, as measured at the RUC Snapshot, is:

$$\mathbf{RUCSFSNAP}_{\,ruc,\,q,\,i} = \mathbf{Max\ (RUCOSFSNAP}_{\,ruc,\,q,\,i}\mathbf{,\ RUCASFSNAP}_{\,ruc,\,q,\,i}\mathbf{)}$$

(~~10~~11) The overall shortfall in MW that a QSE had according to the RUC Snapshot for a 15-minute Settlement Interval is:

$$\mathbf{RUCOSFSNAP}_{\,ruc,\,q,\,i} = \mathbf{Max\ (0,\ ((}\sum_{p}\mathbf{RTAML}_{\,q,\,p,\,i}\mathbf{*\ 4) + ASONPOSSNAP}_{\,ruc,\,q,\,i} - \mathbf{RUCCAPSNAP}_{\,ruc,\,q,\,i}\mathbf{))}$$

The QSE's On-Line Ancillary Service Position according to the RUC Snapshot for a 15-minute Settlement Interval is:

$$\mathbf{ASONPOSSNAP}_{\,ruc,\,q,\,i} = \mathbf{RUPOSSNAP}_{\,ruc,\,q,\,h} + \mathbf{RRPOSSNAP}_{\,ruc,\,q,\,h} + \underline{\mathbf{ECRPOSSNAP}_{\,ruc,\,q,\,h} +}\ \mathbf{Max\ (0,\ (}\cancel{\mathbf{ECRPOSSNAP}_{\,ruc,\,q,\,h}}\ \cancel{+}\mathbf{NSPOSSNAP}_{\,ruc,\,q,\,h} - \sum_{r}\mathbf{ASOFFOFRSNAP}_{\,ruc,\,q,\,r,\,h}\mathbf{))}$$

The amount of capacity that a QSE had according to the RUC Snapshot for a 15-minute Settlement Interval is:

$$\mathbf{RUCCAPSNAP}_{\,ruc,\,q,\,i} = \sum_{r}\mathbf{RCAPSNAP}_{\,ruc,\,q,\,r,\,h} + \mathbf{(RUCCPSNAP}_{\,ruc,\,q,\,h} - \mathbf{RUCCSSNAP}_{\,ruc,\,q,\,h}\mathbf{)} + \mathbf{(}\sum_{p}\mathbf{DAEP}_{\,q,\,p,\,h} - \sum_{p}\mathbf{DAES}_{\,q,\,p,\,h}\mathbf{)} + \mathbf{(}\sum_{p}\mathbf{RTQQEPSNAP}_{\,ruc,\,q,\,p,\,i} - \sum_{p}\mathbf{RTQQESSNAP}_{\,ruc,\,q,\,p,\,i}\mathbf{)} + \sum_{p}\mathbf{DCIMPSNAP}_{\,ruc,\,q,\,p,\,i} + \sum_{r}\mathbf{ASOFRLRSNAP}_{\,ruc,\,q,\,r,\,h}\ \underline{\pm\ \mathbf{ESRMWSNAP}_{\,ruc,\,q,\,h} - \cancel{+}\ \mathbf{ESRASSNAP}_{\,ruc,\,q,\,h}}$$

Where:

The QSE's net up Ancillary Service position (Reg-Up + RRS + ECRS + Non-Spin) covered by the QSE's portfolio of ESRs is:

$$ESRASSNAP_{ruc,\,q,\,h} = \sum_{r} \sum_{ASSubType} ASMWCAPUSNAP_{ruc,\,q,\,h,\,ASSubType,\,r}$$

The sum of the QSE's ESR discharging (positive) or charging (negative) output is:

$$ESRMWSNAP_{ruc,\,q,\,h} = \sum_{r} MWSNAP_{ruc,\,q,\,h,\,r}$$

~~(11) The Ancillary Service shortfall calculation compares the Ancillary Service capability of the QSE, measured by the submitted Ancillary Service Offers, to the Ancillary Service Position. Because the same Resource capacity can be represented in Ancillary Offers for multiple products, the aggregated capability is accounted for by grouping Ancillary Service types in the calculation below. The Ancillary Service shortfall in MW that a QSE had according to the RUC Snapshot for a 15-minute Settlement Interval is:~~

$$\cancel{\mathbf{RUCASFSNAP}_{ruc,\,q,\,i} = \mathbf{Max}\,(0,\, \mathbf{ASCAP1SNAP}_{ruc,\,q,\,i},\, \mathbf{ASCAP2SNAP}_{ruc,\,q,\,i},\, \mathbf{ASCAP3SNAP}_{ruc,\,q,\,i},\, \mathbf{ASCAP4SNAP}_{ruc,\,q,\,i},\, \mathbf{ASCAP5SNAP}_{ruc,\,q,\,i}) + \mathbf{Max}\,(0,\, \mathbf{ASCAP6SNAP}_{ruc,\,q,\,i})}$$

~~Where:~~

$$\cancel{ASCAP1SNAP_{ruc,\,q,\,i} = RUPOSSNAP_{ruc,\,q,\,h} - \sum_{r} ASOFR1SNAP_{ruc,\,q,\,r,\,h}}$$

$$\cancel{ASCAP2SNAP_{ruc,\,q,\,i} = RRPOSSNAP_{ruc,\,q,\,h} - \sum_{r} ASOFR2SNAP_{ruc,\,q,\,r,\,h}}$$

$$\cancel{ASCAP3SNAP_{ruc,\,q,\,i} = (RUPOSSNAP_{ruc,\,q,\,h} + RRPOSSNAP_{ruc,\,q,\,h}) - \sum_{r} ASOFR3SNAP_{ruc,\,q,\,r,\,h}}$$

$$\cancel{ASCAP4SNAP_{ruc,\,q,\,i} = (RUPOSSNAP_{ruc,\,q,\,h} + RRPOSSNAP_{ruc,\,q,\,h} + ECRPOSSNAP_{ruc,\,q,\,h}) - \sum_{r} ASOFR4SNAP_{ruc,\,q,\,r,\,h}}$$

$$\cancel{ASCAP5SNAP_{ruc,\,q,\,i} = (RUPOSSNAP_{ruc,\,q,\,h} + RRPOSSNAP_{ruc,\,q,\,h} + ECRPOSSNAP_{ruc,\,q,\,h} + NSPOSSNAP_{ruc,\,q,\,h}) - \sum_{r} ASOFR5SNAP_{ruc,\,q,\,r,\,h}}$$

$$\cancel{ASCAP6SNAP_{ruc,\,q,\,i} = RDPOSSNAP_{ruc,\,q,\,h} - \sum_{r} ASOFR6SNAP_{ruc,\,q,\,r,\,h}}$$

(12) The Ancillary Service shortfall in MW that a QSE had according to the RUC Snapshot for a 15-minute Settlement Interval is:

$$\textbf{RUCASFSNAP}_{\,ruc,\,q,\,i} = \textbf{RUPOSSNAP}_{\,ruc,\,q,\,h} + \textbf{RDPOSSNAP}_{\,ruc,\,q,\,h} + \textbf{RRPOSSNAP}_{\,ruc,\,q,\,h} + \textbf{ECRPOSSNAP}_{\,ruc,\,q,\,h} + \textbf{NSPOSSNAP}_{\,ruc,\,q,\,h} - \textbf{ASMWCAPUQSNAP}_{\,ruc,\,q,\,h}$$

Where:

$$\text{ASMWCAPUQSNAP}_{\,ruc,\,q,\,h} = \sum_{r} \sum_{ASSubType} \text{ASMWCAPUSNAP}_{\,ruc,\,q,\,h,\,ASSubType,\,r}$$

$$\text{RRPOSSNAP}_{\,ruc,\,q,\,h} = \text{Max}(0,\ \text{PFPOSSNAP}_{\,ruc,\,q,\,h} + \text{Max}(0,\ \text{UFPOSSNAP}_{\,ruc,\,q,\,h} + \text{FFPOSSNAP}_{\,ruc,\,q,\,h}))$$

$$\text{ECRPOSSNAP}_{\,ruc,\,q,\,h} = \text{Max}(0,\ \text{ECSPOSSNAP}_{\,ruc,\,q,\,h} + \text{ECMPOSSNAP}_{\,ruc,\,q,\,h})$$

$$\text{NSPOSSNAP}_{\,ruc,\,q,\,h} = \text{Max}(0,\ \text{NSSPOSSNAP}_{\,ruc,\,q,\,h} + \text{NSMPOSSNAP}_{\,ruc,\,q,\,h})$$

(~~12~~13) The RUC Shortfall in MW for one QSE for one 15-minute Settlement Interval, as measured at the end of the Adjustment Period, is:

$$\textbf{RUCSFADJ}_{\,ruc,\,q,\,i} = \textbf{Max}\ (\textbf{RUCOSFADJ}_{\,ruc,\,q,\,i},\ \textbf{RUCASFADJ}_{\,q,\,i})$$

(~~13~~14) The overall shortfall in MW that a QSE had at the end of the Adjustment Period for a 15-minute Settlement Interval, but including capacity from IRRs as seen in the RUC Snapshot, is:

$$\textbf{RUCOSFADJ}_{\,ruc,\,q,\,i} = \textbf{Max}\ (0,\ ((\sum_{p} \textbf{RTAML}_{\,q,\,p,\,i} * 4) + \textbf{ASONPOSADJ}_{\,q,\,i} - (\sum_{r=IRRsOnly} \textbf{RCAPSNAP}_{\,ruc,\,q,\,r,\,h} + \textbf{RUCCAPADJ}_{\,q,\,i})))$$

Where:

The On-Line Ancillary Service Position the QSE had at the end of the Adjustment Period for a 15-minute Settlement Interval is:

$$\text{ASONPOSADJ}_{\,q,\,i} = \text{RUPOSADJ}_{\,q,\,h} + \text{RRPOSADJ}_{\,q,\,h} + \text{ECRPOSADJ}_{\,q,\,h} + \text{Max}\ (0,\ (\cancel{\text{ECRPOSADJ}_{\,q,\,h} +}\ \text{NSPOSADJ}_{\,q,\,h} - \sum_{r} \text{ASOFFOFRADJ}_{\,q,\,r,\,h}))$$

The amount of capacity that a QSE had at the end of the Adjustment Period for a 15-minute Settlement Interval, excluding capacity from IRRs, is:

$$\text{RUCCAPADJ}_{q,\,i} = \sum_{r}\text{RCAPADJ}_{q,\,r,\,h} + (\text{RUCCPADJ}_{q,\,h} - \text{RUCCSADJ}_{q,\,h}) + (\sum_{p}\text{DAEP}_{q,\,p,\,h} - \sum_{p}\text{DAES}_{q,\,p,\,h}) + (\sum_{p}\text{RTQQEPADJ}_{q,\,p,\,i} - \sum_{p}\text{RTQQESADJ}_{q,\,p,\,i}) + \sum_{p}\text{RTDCIMP}_{q,\,p} + \sum_{r}\text{ASOFRLRADJ}_{q,\,r,\,h}$$

$$\underline{+\ \text{ESRMWADJ}_{q,\,h} + \text{ESRASADJ}_{q,\,h}}$$

Where:

The QSE's net up Ancillary Service position (Reg-Up + RRS + ECRS + Non-Spin) covered by the QSE's portfolio of ESRs is:

$$\underline{\text{ESRASADJ}_{q,\,h} = \sum_{r}\sum_{ASSubType}\text{ASMWCAPUADJ}_{q,\,h,\,ASSubType,\,r}}$$

The sum of the QSE's ESR discharging (positive) or charging (negative) output is:

$$\underline{\text{ESRMWADJ}_{q,\,h} = \sum_{r}\text{MWADJ}_{q,\,h,\,r}}$$

~~(14) The Ancillary Service shortfall calculation compares the Ancillary Service capability of the QSE, measured by the submitted Ancillary Service Offers, to the Ancillary Service Position. Because the same Resource capacity can be represented in Ancillary Offers for multiple products, the aggregated capability is accounted for by grouping Ancillary Service types in the calculation below. The Ancillary Service shortfall in MW that a QSE had at the end of the Adjustment Period for a 15-minute Settlement Interval is:~~

$$\cancel{\mathbf{RUCASFADJ}_{q,\,i} = \mathbf{Max}\ (0, \mathbf{ASCAP1ADJ}_{q,\,i}, \mathbf{ASCAP2ADJ}_{q,\,i}, \mathbf{ASCAP3ADJ}_{q,\,i}, \mathbf{ASCAP4ADJ}_{q,\,i}, \mathbf{ASCAP5ADJ}_{q,\,i}) + \mathbf{Max}\ (0, \mathbf{ASCAP6ADJ}_{q,\,i})}$$

~~Where:~~

$$\cancel{\text{ASCAP1ADJ}_{q,\,i} = \text{RUPOSADJ}_{q,\,h} - \sum_{r}\text{ASOFR1ADJ}_{q,\,r,\,h}}$$

$$\cancel{\text{ASCAP2ADJ}_{q,\,i} = \text{RRPOSADJ}_{q,\,h} - \sum_{r}\text{ASOFR2ADJ}_{q,\,r,\,h}}$$

$$\cancel{\text{ASCAP3ADJ}_{q,\,i} = (\text{RUPOSADJ}_{q,\,h} + \text{RRPOSADJ}_{q,\,h}) - \sum_{r}\text{ASOFR3ADJ}_{q,\,r,\,h}}$$

$$\cancel{\text{ASCAP4ADJ}_{q,\,i} = (\text{RUPOSADJ}_{q,\,h} + \text{RRPOSADJ}_{q,\,h} + \text{ECRPOSADJ}_{q,\,h}) - \sum_{r}\text{ASOFR4ADJ}_{q,\,r,\,h}}$$

~~$ASCAP5ADJ_{q,i} = (RUPOSADJ_{q,h} + RRPOSADJ_{q,h} + ECRPOSADJ_{q,h} + NSPOSADJ_{q,h}) - \sum_{r} ASOFR5ADJ_{q,r,h}$~~

~~$ASCAP6ADJ_{q,i} = RDPOSADJ_{q,h} - \sum_{r} ASOFR6ADJ_{q,r,h}$~~

(15) The Ancillary Service shortfall in MW that a QSE had at the end of the Adjustment Period for a 15-minute Settlement Interval is:

$$\mathbf{RUCASFADJ_{q,i} = RUPOSADJ_{q,h} + RDPOSADJ_{q,h} + RRPOSADJ_{q,h} + ECRPOSADJ_{q,h} + NSPOSADJ_{q,h} - ASMWCAPUQADJ_{q,h}}$$

Where:

$$ASMWCAPUQADJ_{q,h} = \sum_{r} \sum_{ASSubType} ASMWCAPUADJ_{q,h,ASSubType,r}$$

$$RRPOSADJ_{q,h} = Max(0, PFPOSADJ_{q,h} + Max(0, UFPOSADJ_{q,h} + FFPOSADJ_{q,h}))$$

$$ECRPOSADJ_{q,h} = Max(0, ECSPOSADJ_{q,h} + ECMPOSADJ_{q,h})$$

$$NSPOSADJ_{q,h} = Max(0, NSSPOSADJ_{q,h} + NSMPOSADJ_{q,h})$$

The above variables are defined as follows:

Variable	Unit	Definition
$RUCSFRS_{ruc,i,q}$	none	*RUC Shortfall Ratio Share*—The ratio of the QSE *q*'s capacity shortfall to the sum of all QSEs' capacity shortfalls, for the RUC process *ruc*, for the 15-minute Settlement Interval *i*.
$RUCSF_{ruc,i,q}$	MW	*RUC Shortfall*—The QSE *q*'s capacity shortfall for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
$RUCSFTOT_{ruc,i}$	MW	*RUC Shortfall Total*—The sum of all QSEs' capacity shortfalls, for a RUC process *ruc*, for a 15-minute Settlement Interval *i*.
$RUCSFSNAP_{ruc,q,i}$	MW	*RUC Shortfall at Snapshot*—The QSE *q*'s capacity shortfall will be the maximum of the QSE's overall shortfall or Ancillary Service shortfall, as calculated for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
$RUCSFADJ_{ruc,q,i}$	MW	*RUC Shortfall at End of Adjustment Period*—The QSE *q*'s end of Adjustment Period capacity shortfall will be the maximum of the QSE's overall shortfall or Ancillary Service shortfall, as calculated for the RUC process *ruc*, for the 15-minute Settlement Interval *i*.
$RUCCAPCREDIT_{q,i,z}$	MW	*RUC Capacity Credit*—The QSE *q*'s capacity credit resulting from capacity paid through the RUC Capacity-Short Amount for RUC process *z* for the 15-minute Settlement Interval *i*.

RUCOSFSNAP $_{ruc,\ q,\ i}$	MW	*RUC Overall Shortfall at Snapshot* —The QSE *q*'s overall capacity shortfall according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
RUCASFSNAP $_{ruc,\ q,\ i}$	MW	*RUC Ancillary Service Shortfall at Snapshot* —The QSE *q*'s Ancillary Service capacity shortfall according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
ASONPOSSNAP $_{ruc\ ,q\ ,i}$	MW	*Ancillary Service On-Line Position at Snapshot* – The QSE *q's* total On-Line Ancillary Service position according to the RUC Snapshot for the RUC process *ruc* for the 15-minute Settlement Interval *i*.
RUPOSSNAP $_{ruc,\ q,\ h}$	MW	*Regulation Up Position at Snapshot* —The QSE *q's* net positive Real-Time Reg-Up Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
RRPOSSNAP $_{ruc,\ q,\ h}$	MW	*Responsive Reserve Service Position at Snapshot* —The QSE *q's* net positive Real-Time RRS Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
ECRPOSSNAP $_{ruc,\ q,\ h}$	MW	*ERCOT Contingency Reserve Service Position at Snapshot* —The QSE *q's* net positive Real-Time ECRS Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
NSPOSSNAP $_{ruc,\ q,\ h}$	MW	*Non-Spin Reserve Service Position at Snapshot* —The QSE *q's* net positive Real-Time Non-Spin Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
RDPOSSNAP $_{ruc,\ q,\ h}$	MW	*Regulation Down Position at Snapshot* —The QSE *q's* net positive Real-Time Regulation Down Service (Reg-Down) Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
ASOFFOFRSNAP $_{ruc,\ q,\ r,\ h}$	MW	*Ancillary Service Offline Offers at Snapshot* –The capacity represented by validated Ancillary Service Offers for ~~ECRS and~~ Non-Spin for Resource *r* with COP status of "OFF", represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. Where for a Combined Cycle Train, the Resource *r* is a Combined Cycle Generation Resource within the Combined Cycle Train. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.
ASOFRLRSNAP $_{ruc,\ q,\ r,\ h}$	MW	*Ancillary Service Offer per Load Resource at Snapshot* – The capacity represented by validated Ancillary Service Offers for Reg-Up, Non-Spin, RRS, and ECRS for the Load Resource *r* represented by QSE *q* according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. A Resource's offered capacity is only included in the sum to the extent that the Resource's COP Status and Ancillary Service Capability indicate it would be capable of providing the Ancillary Service during the hour *h*.

PFPOSSNAP $_{ruc, q, h}$	MW	*Responsive Reserve (Governor Response or Governor-Like Response) Position at Snapshot*—The QSE *q's* net Real-Time RRS-PFR Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
UFPOSSNAP $_{ruc, q, h}$	MW	*Responsive Reserve (Under Frequency trigger at 59.7 Hz.) Position at Snapshot*—The QSE *q's* net Real-Time RRS-UFR Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
FFPOSSNAP $_{ruc, q, h}$	MW	*Responsive Reserve (Fast Frequency Response) Position at Snapshot*—The QSE *q's* net positive Real-Time RRS-FFR Ancillary Service Position according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
ECSPOSSNAP $_{ruc, q, h}$	MW	*ERCOT Contingency Reserve Service (SCED Dispatchable) Position at Snapshot*—The QSE *q's* net ECRS Ancillary Service Position that is SCED-dispatchable according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
ECMPOSSNAP $_{ruc, q, h}$	MW	*ERCOT Contingency Reserve Service (Non-SCED Dispatchable) Position at Snapshot*—The QSE *q's* net positive ECRS Ancillary Service Position that is non-SCED-dispatchable according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
NSSPOSSNAP $_{ruc, q, h}$	MW	*Non-Spin Reserve Service (SCED Dispatchable) Position at Snapshot*—The QSE *q's* net Non-Spin Ancillary Service Position that is SCED-dispatchable according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval. This value can be positive or negative.
NSMPOSSNAP $_{ruc, q, h}$	MW	*Non-Spin Reserve Service (Non-SCED Dispatchable) Position at Snapshot*—The QSE *q's* net positive Non-Spin Ancillary Service Position that is non-SCED-dispatchable according to the RUC Snapshot for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
ASMWCAPUQSNAP $_{ruc, q, h}$	MW	*Calculated Total MW Capacity used to cover the QSE's Ancillary Service Position at Snapshot*—The calculated total MW capacity for a QSE *q* that represents the amount of the QSE's Ancillary Service Position covered by its Resources for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.
ASMWCAPUSNAP $_{ruc, q, h, ASSubtype, r}$	MW	*Calculated MW Capacity used to cover the QSE's 'AStype' Ancillary Service Position at Snapshot*—The calculated MW Capacity of a Resource *r* represented by QSE *q* that is used to cover its QSE's "ASSubtype" Ancillary Service Position for the RUC process *ruc* for the hour *h* that includes the 15-minute Settlement Interval.